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Office of Solid Waste
and Emergency Response
Washington, DC 20460

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Solid Waste

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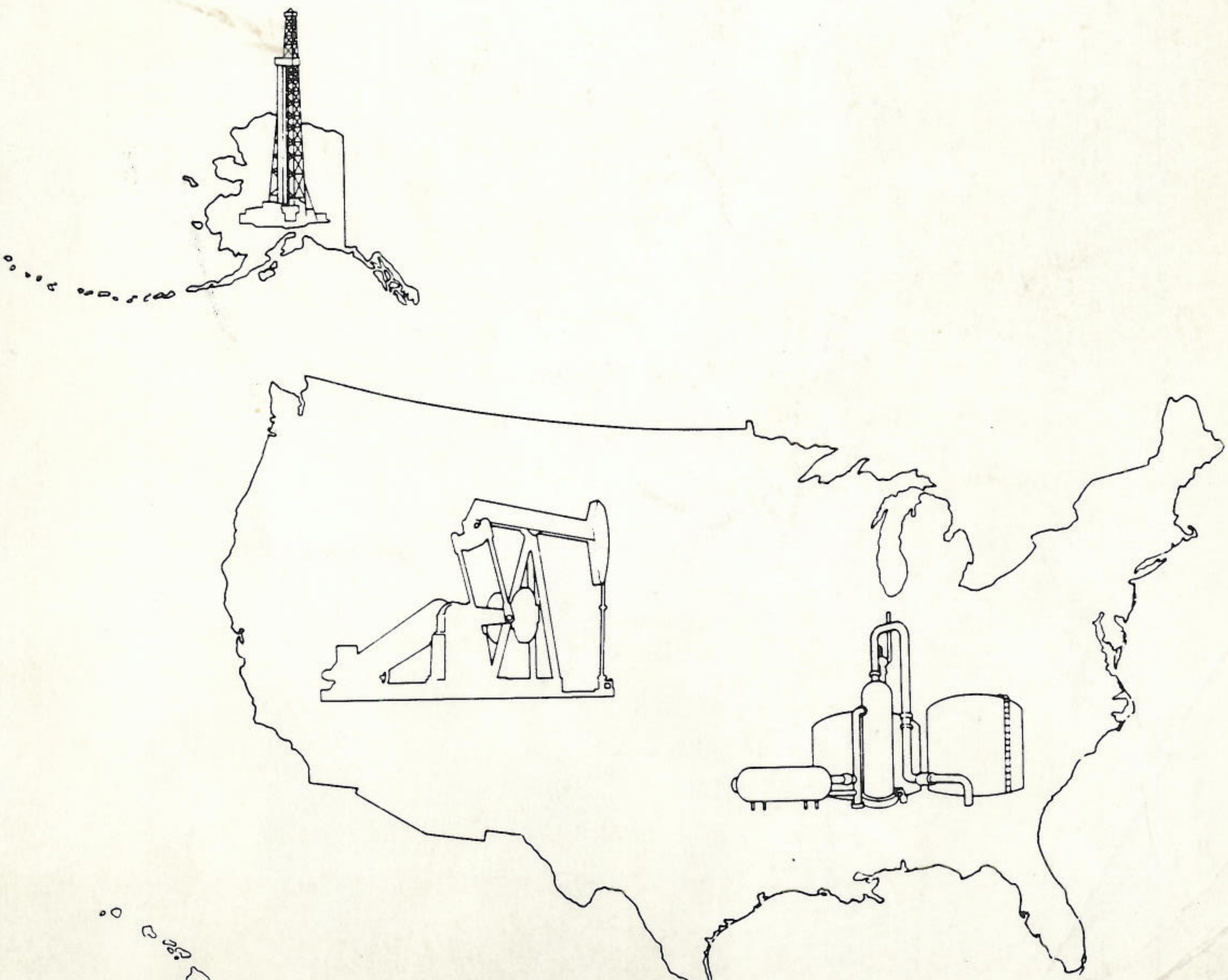
Report to Congress

Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy

Volume 1 of 3
Oil and Gas



REPORT TO CONGRESS

MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT, AND PRODUCTION OF CRUDE OIL, NATURAL GAS, AND GEOTHERMAL ENERGY

VOLUME 1 OF 3

OIL AND GAS

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

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CHAPTER I

INTRODUCTION

STATUTORY REQUIREMENTS AND GENERAL PURPOSE

Under Section 3001(b)(2)(A) of the 1980 Amendments to the Resource Conservation and Recovery Act (RCRA), Congress temporarily exempted several types of solid wastes from regulation as hazardous wastes, pending further study by the Environmental Protection Agency (EPA).[1] Among the categories of wastes exempted were "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy." Section 8002(m) of the Amendments requires the Administrator to study these wastes and submit a final report to Congress. This report responds to those requirements. Because of the many inherent differences between the oil and gas industry and the geothermal energy industry, the report is submitted in three volumes. Volume 1 (this volume) covers the oil and gas industry; Volume 2 covers the geothermal energy industry; Volume 3 covers State regulatory summaries for the oil and gas industry and includes a glossary of terms. This report discusses wastes generated only by the onshore segment of the oil and gas industry.

The original deadline for this study was October 1982. EPA failed to meet that deadline, and in August 1985 the Alaska Center for the Environment sued the Agency for its failure to conduct the study.

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[1] EPA is also required to make regulatory determinations affecting the oil and gas and geothermal energy industries under several other major statutes. These include designing appropriate effluent limitations guidelines under the Clean Water Act, determining emissions standards under the Clean Air Act, and implementing the requirements of the underground injection control program under the Safe Drinking Water Act.

EPA entered into a consent order, obligating it to submit the final Report to Congress on or before August 31, 1987. In April 1987, this schedule was modified and the deadline for submittal of the final Report to Congress was extended to December 31, 1987.

Following submission of the current study, and after public hearings and opportunity for comment, the Administrator of EPA must determine either to promulgate regulations under the hazardous waste management provisions of RCRA (Subtitle C) or to declare that such regulations are unwarranted. Any regulations would not take effect unless authorized by an act of Congress.

This does not mean that the recommendations of this report are limited to a narrow choice between application of full Subtitle C regulation and continuation of the current exemption. Section 8002(m) specifically requires the Administrator to propose recommendations for "[both] Federal and non-Federal actions" to prevent or substantially mitigate any adverse effects associated with management of wastes from these industries. EPA interprets this statement as a directive to consider the practical and prudent means available to avert health or environmental damage associated with the improper management of oil, gas, or geothermal wastes. The Agency has identified a wide range of possible actions, including voluntary programs, cooperative work with States to modify their programs, and Federal action outside of RCRA Subtitle C, such as RCRA Subtitle D, the existing Underground Injection Control Program under the Safe Drinking Water Act, or the National Pollution Discharge Elimination System under the Clean Water Act.

In this light, EPA emphasizes that the recommendations presented here do not constitute a regulatory determination. Such a determination cannot be made until the public has had an opportunity to review and comment on this report (i.e., the determination cannot be made until June 1988). Furthermore, the Agency is, in several important areas, presenting optional approaches involving further research and consultation with the States and other affected parties.

STUDY APPROACH

The study factors are listed in the various paragraphs of Section 8002(m), which is quoted in its entirety as Exhibit 1 (page I-13). For clarity, the Agency has designed this report to respond specifically to each study factor within separate chapters or sections of chapters. It is important to note that although every study factor has been weighed in arriving at the conclusions and recommendations of this report, no single study factor has a determining influence on the conclusions and recommendations.

The study factors are defined in the paragraphs below, which also introduce the methodologies used to analyze each study area with respect to the oil and gas industry. More detailed methodological discussions can be found later in this report and in the supporting documentation and appendices.

STUDY FACTORS

The principal study factors of concern to Congress are listed in subparagraphs (A) through (G) of Section 8002(m)(1) (see Exhibit 1). The introductory and concluding paragraphs of the Section, however, also contain directives to the Agency on the content of this study. This work has therefore been organized to respond to the following comprehensive interpretation of the 8002(m) study factors.

<u>Study Factor 1 - Defining Exempt Wastes</u>

RCRA describes the exempt wastes in broad terms, referring to "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy." The Agency, therefore, relied to the extent possible on the legislative history of the amendments, which provides guidance on the definition of other wastes. The tentative scope of the exemption is discussed in Chapter II of this volume.

Study Factor 2 - Specifying the Sources and Volumes of Exempt Wastes

In response to Section 8002(m)(1)(A), EPA has developed estimates of the sources and volumes of all exempt wastes. The estimates are presented in Chapter II, "Overview of the Industry."

Comprehensive information on the volumes of exempt wastes from oil and gas operations is not routinely collected nationwide; however, estimates of total volumes produced can be made through a variety of approaches.

With respect to drilling muds and related wastes, two methods for estimating volumes are presented. The first, developed early in the study by EPA, estimates drilling wastes as a function of the size of reserve pits. The second method is based on a survey conducted by the American Petroleum Institute (API) on production of drilling muds and completion fluids, cuttings, and other associated wastes discharged to reserve pits. Both methods and their results are included in Chapter II.

Similarly, EPA and API developed independent estimates of produced water volumes. EPA's first estimates were based on a survey of the injection, production, and hauling reports of State agencies; API's were based on its own survey of production operations. Again, this report presents the results of both methodologies.

Study Factor 3 - Characterizing Wastes

Section 8002(m) does not directly call for a laboratory analysis of the exempted wastes, but the Agency considers such a review to be a necessary and appropriate element of this study. Analysis of the principal high-volume wastes (i.e., drilling fluids and produced waters) can help to indicate whether any of the wastes may be hazardous under the

definitions of RCRA Subtitle C. Wastes were examined with regard to whether they exhibited any of the hazardous characteristics defined under 40 CFR 261 of RCRA, including extraction procedure toxicity, ignitability, corrosivity, and reactivity. Also, a compositional analysis was performed for the purpose of determining if hazardous constituents were present in the wastes at concentrations exceeding accepted health-based limits.

EPA therefore conducted a national screening type program that sampled facilities to compile relevant data on waste characteristics. Sites were selected at random in cooperation with State regulatory agencies, based on a division of the United States into zones (see Figure I-1). Samples were subjected to extensive analysis, and the results were subjected to rigorous quality control procedures prior to their publication in January 1987. Simultaneously, using a different sampling methodology, API sampled the same sites and wastes covered by the EPA-sponsored survey. Chapter II of this report, "Overview of the Industry," presents a summary of results of both programs.

Study Factor 4 - Describing Current Disposal Practices

Section 8002(m)(1)(B) calls for an analysis of current disposal practices for exempted wastes. Chapter III, "Current and Alternative Waste Management Practices," summarizes EPA's review, which was based on a number of sources. Besides reviewing the technical literature, EPA sent representatives to regulatory agencies of the major oil- and gas-producing States to discuss current waste management technologies with State representatives. In addition, early drafts of this study's characterizations of such technologies were reviewed by State and industry representatives.

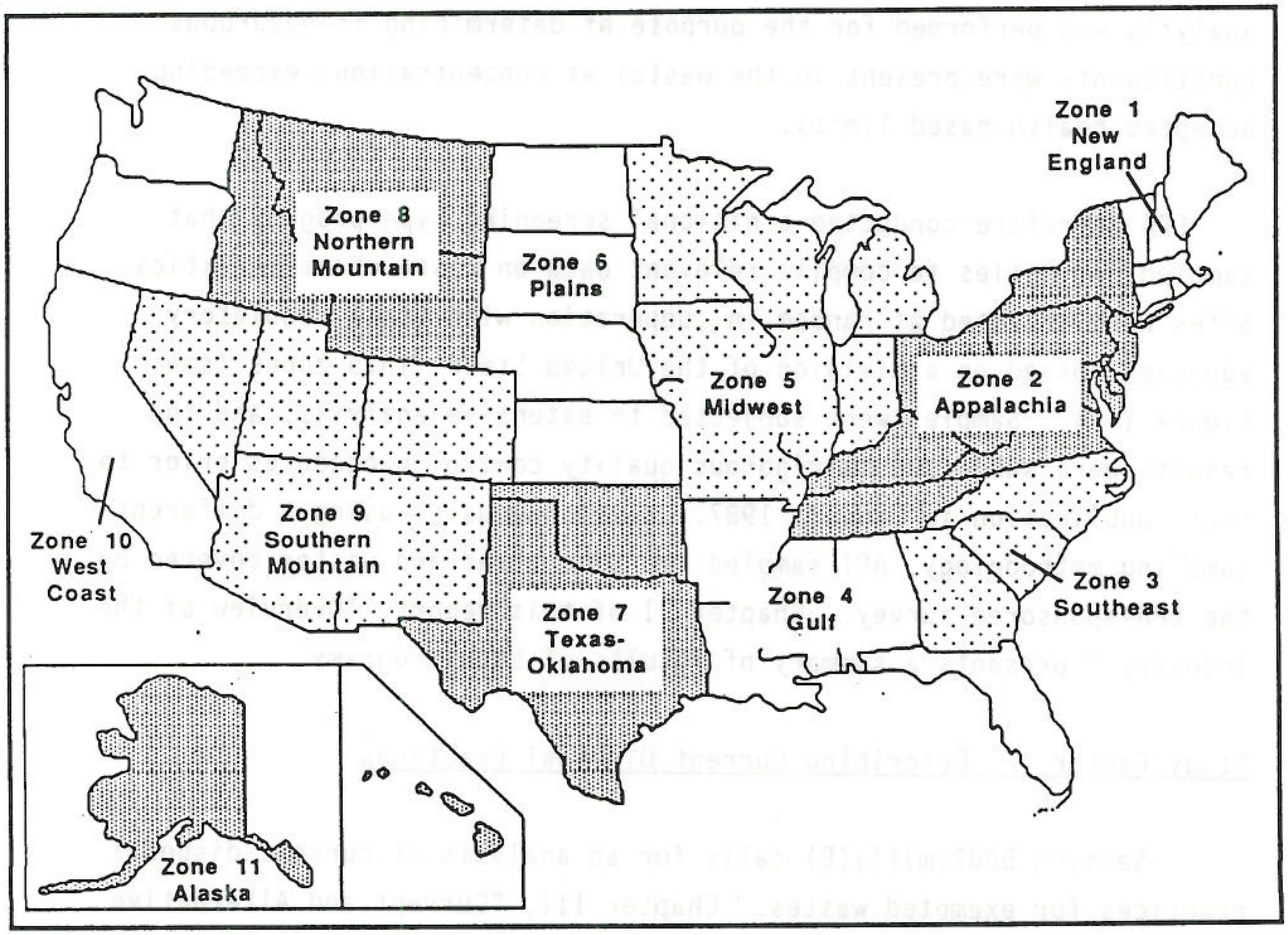

Figure I-1
Oil and Gas Production Zones
Divisions of the United States
Used for the
RCRA Section 8002(m) Study of
Oil and Gas Wastes

The Agency intentionally has not compiled an exhaustive review of waste management technologies used by the oil and gas industry. As stressed throughout this volume, conditions and methods vary widely from State to State and operation to operation. Rather, the Agency has described the principal and common methods of managing field-generated wastes and has discussed these practices in general and qualitative terms in relation to their effectiveness in protecting human health and the environment.

<u>Study Factor 5 - Documenting Evidence of Damage to Human Health and the Environment Caused by Management of Oil and Gas Wastes</u>

Section 8002(m)(1)(D) requires EPA to analyze "documented cases" of health and environmental damage related to surface runoff or leachate. Although EPA has followed this instruction, paragraph (1) of the section also refers to "adverse effects of such wastes [i.e., exempted wastes, not necessarily only runoff and leachate] on humans, water, air, health, welfare, and natural resources...."

Chapter IV, "Damage Cases," summarizes EPA's effort to collect documented evidence of harm to human health, the environment, or valuable resources. Cases were accepted for presentation in this report only if, prior to commencement of field work, they met the standards of the test of proof, defined as (1) a scientific study, (2) an administrative finding of damage under State or other applicable authority, or (3) determination of damage by a court. Many cases met more than one such test of proof.

A number of issues of interpretation have been raised that must be clarified at the outset. First, <u>in the Agency's opinion</u>, the case study approach, such as that called for by Section 8002(m), is intended only to define the nature and range of known damages, not to estimate the frequency or extent of damages associated with typical operations. The

results presented here should not be interpreted as having statistical significance. The number of cases reported in each category bears no statistically significant relationship to the actual types and distribution of damages that may or may not exist across the United States.

Second, the total number of cases bears no implied or intended relationship to the total extent of damage from oil or gas operations caused at present or in the past.

Third, Section 8002(m)(1)(D) makes no mention of defining relationships between documented damages and violations of State or other Federal regulations. As a practical necessity, EPA has in fact relied heavily on State enforcement and complaint files in gathering documentation for this section of the report.[2] Consequently, a large proportion of cases reported here involve violations of State regulations. However, the fact that the majority of cases presented here involve State enforcement actions implies nothing, positive or negative, about the success of State programs in enforcing their requirements on industry.

Study Factor 6 - Assessing Potential Danger to Human Health or the Environment from the Wastes

Section 8002(m)(1)(C) requires analysis of the potential dangers of surface runoff and leachate. These potential effects can involve all types of damages over a long period of time and are not necessarily limited to the categories of damages for which documentation is currently available.

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[2] Other sources have included evidence submitted by private citizens or supplied by attorneys in response to inquiries from EPA researchers.

Several methods of estimating potential damages are available, and EPA has combined two approaches in responding to this study factor in Chapter V, "Risk Modeling." The first has been to use quantitative risk assessment modeling techniques developed for use elsewhere in the RCRA program. The second has been to apply more qualitative methods, based on traditional environmental assessment techniques.

The goal of both the quantitative and the qualitative risk assessments has been to define the most important factors in causing or averting human health risk and environmental risk from field operations. For the quantitative evaluation, EPA has adapted the EPA Liner Location Model, which was built to evaluate the impacts of land disposal of hazardous wastes, for use in analyzing drilling and production conditions. Since oil and gas operations are in many ways significantly different from land disposal of hazardous wastes, all revisions to the Liner Location Model and assumptions made in its present application have been extensively documented and are summarized in Chapter V. The procedures of traditional environmental assessment needed no modification to be applied.

As is true in the damage case work, the results of the modeling analysis have no statistical significance in terms of either the pattern or the extent of damages projected. The Agency modeled a subset of prototype situations, designed to roughly represent significant variations in conditions across the country. The results are very useful for characterizing the interactions of technological, geological, and climatic differences as they influence the potential for damages.

<u>Study Factor 7 - Reviewing the Adequacy of Government and Private Measures to Prevent and/or Mitigate any Adverse Effects</u>

Section 8002 (m)(1) requires that the report's conclusions of any adverse effects associated with current management of exempted wastes

include consideration of the "adequacy of means and measures currently employed by the oil and gas industry, Government agencies, and others" to dispose of or recycle wastes or to prevent or mitigate those adverse effects.

Neither the damage case assessment nor the risk assessment provided statistically representative data on the extent of damages, making it impossible to compare damages in any quantitative way to the presence and effectiveness of control efforts. The Agency's response to this requirement is therefore based on a qualitative assessment of all the materials gathered during the course of assembling the report and on a review of State regulatory programs presented in Chapter VII, "Current Regulatory Programs." Chapter VII reviews the elements of programs and highlights possible inconsistencies, lack of specificity, potential problems in implementation, or gaps in coverage. Interpretation of the adequacy of these control efforts is presented in Chapter VIII, "Conclusions."

Study Factor 8 - Defining Alternatives to Current Waste Management Practices

Section 8002 (m)(1) requires EPA to analyze alternatives to current disposal methods. EPA's discussion in response to this study factor is incorporated in Chapter III, "Current and Alternative Waste Management Practices."

Chapter III merges the concepts of current and alternative waste management practices. It does not single out particular technologies as potential substitutes for current practices because of the wide variation in practices among States and among different types of operations. Furthermore, waste management technology in this field is fairly simple. At least for the major high-volume waste streams, no significant, field-proven, newly invented technologies that can be considered "innovative" or "emerging" are in the research or development stage.

Practices that are routine in one location may be considered innovative or alternative elsewhere. On the other hand, virtually every waste management practice that exists can be considered "current" in one specific situation or another.

This does not mean that improvements are not possible: in some cases, currently available technologies may not be properly selected, implemented, or maintained. Near-term improvements in waste management in these industries will likely be based largely on more effective use of what is already available.

Study Factor 9 - Estimating the Costs of Alternative Practices

Subparagraph (F) calls for analysis of costs of alternative practices. The first several sections of Chapter VI, "Costs and Economic Impacts of Alternative Waste Management Practices," present the Agency's analysis of this study factor.

For the purposes of this report, EPA based its cost estimates on 21 prototypical regional projects, defined so as to capture significant differences between major and independent companies and between stripper operations and other projects. The study evaluates costs of waste disposal only for the two principal high-volume waste streams of concern, drilling fluids and produced waters, employing as its baseline the use of unlined reserve pits located at the drill site and the disposal of produced waters in injection wells permitted under the Federal Underground Injection Control Program and located off site.

The study then developed two alternative scenarios that varied the incremental costs of waste management control technology, applied them to each prototype project, and modeled the cost impacts of each. The

first scenario imposes a set of requirements typical of full Subtitle C management rules; the second represents a less stringent and extensive range of requirements based, in essence, on uniform nationwide use of the most up-to-date and effective controls now being applied by any of the States. Model results indicate cumulative annual costs, at the project level, of each of the more stringent control scenarios.

Study Factor 10 - Estimating the Economic Impacts on Industry of Alternative Practices

In response to the requirements of subparagraph (G), the final two sections of Chapter VI present the Agency's analysis of the potential economic impacts of nationwide imposition of the two control scenarios analyzed at the project level.

Both the cost and the economic impact predicted in this report are admittedly large. Many significant variations influence the economics of this industry and make it difficult to generalize about impacts on either the project or the national level. In particular, the price of oil itself greatly affects both levels. Fluctuations in the price of oil over the period during which this study was prepared have had a profound influence on project economics, making it difficult to draw conclusions about the current or future impacts of modified waste management practices.

Nevertheless, the Agency believes that the analysis presented here is a reasonable response to Congress's directives, and that the results, while they cannot be exact, accurately reflect the general impacts that might be expected if environmental control requirements were made more stringent.

EXHIBIT 1:
Section 8002(m) Resource Conservation and Recovery Act as amended by PL 96-482

"(m) Drilling Fluids, Produced Waters, and Other Wastes Associated with the Extraction, Development, or Production of Crude Oil or Natural Gas or Geothermal Energy.- (1) The Administrator shall conduct a detailed and comprehensive study and submit a report on the adverse effects, if any, of drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy on human health and the environment, including, but not limited to the effects of such wastes on humans, water, air, health, welfare, and natural resources and on the adequacy of means and measures currently employed by the oil and gas and geothermal drilling and production industry, Government agencies, and others to dispose of and utilize such wastes and to prevent or substantially mitigate such adverse effects. Such study shall include an analysis of-

"(A) the sources and volume of discarded material generated per year from such wastes;

"(B) present disposal practices:

"(C) potential danger to human health and the environment from the surface runoff or leachate;

"(D) documented cases which prove or have caused danger to human health and the environment from surface runoff or leachate;

"(E) alternatives to current disposal methods:

"(F) the cost of such alternatives; and

"(G) the impact of those alternatives on the exploration for, and development and production of, crude oil and natural gas or geothermal energy.

In furtherance of this study, the Administrator shall, as he deems appropriate, review studies and other actions of other Federal agencies concerning such wastes with a view toward avoiding duplication of effort and the need to expedite such study. The Administrator shall publish a report of such and shall include appropriate findings and recommendations for Federal and non-Federal actions concerning such effects.

"(2) The Administrator shall complete the research and study and submit the report required under paragraph (1) not later than twenty-four months from the date of enactment of the Solid Waste Disposal Act Amendments of 1980. Upon completion of the study, the Administrator shall prepare a summary of the findings of the study, a plan for research, development, and demonstration respecting the findings of the study, and shall submit the findings and the study, along with any recommendations resulting from such study, to the Committee on Environment and Public Works of the United States Senate and the Committee on Interstate and Foreign Commerce of the United states House of Representatives.

"(3) There are authorized to be appropriations not to exceed $1,000,000 to carry out the provisions of this subsection.

(m) Drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy—(1) The Administrator shall conduct a detailed and comprehensive study and submit a report on the adverse effects, if any, of drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas or geothermal energy on human health and the environment, including, but not limited to the effects of such wastes on humans, water, air, health, welfare, and natural resources and on the adequacy of means and measures currently employed by the oil and gas and geothermal drilling and production industry, Government agencies, and others to dispose of and utilize such wastes and to prevent or substantially mitigate such adverse effects. Such study shall include an analysis of—

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In furtherance of this study, the Administrator shall as he deems appropriate, review studies and other actions of other Federal agencies concerning such wastes with a view toward avoiding duplication of effort and the need to expedite such study. The Administrator shall publish a report of such study and shall include appropriate findings and recommendations for Federal and non-Federal actions concerning such effects.

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(3) There are authorized to be appropriated not to exceed $1,000,000 to carry out the provisions of this subsection.

CHAPTER II

OVERVIEW OF THE INDUSTRY

DESCRIPTION OF THE OIL AND GAS INDUSTRY

The oil and gas industry explores for, develops, and produces petroleum resources. In 1985 there were approximately 842,000 producing oil and gas wells in this country, distributed throughout 38 States. They produced 8.4 million barrels[1] of oil, 1.6 million barrels of natural gas liquids, and 44 billion cubic feet of natural gas daily. The American Petroleum Institute estimates domestic reserves at 28.4 billion barrels of oil, 7.9 billion barrels of natural gas liquids, and 193 trillion cubic feet of gas. Petroleum exploration, development, and production industries employed approximately 421,000 people in 1985.[2]

The industry is as varied as it is large. Some aspects of exploration, development, and production can change markedly from region to region and State to State. Well depths range from as little as 30 to 50 feet in some areas to over 30,000 feet in areas such as the Anadarko Basin of Oklahoma. Pennsylvania has been producing oil for 120 years; Alaska for only 15. Maryland has approximately 14 producing wells; Texas has 269,000 and completed another 25,721 in 1985 alone. Production from a single well can vary from a high of about 11,500 barrels per day (the 1985 average for wells on the Alaska North Slope) to less than 10 barrels per day for many thousands of "stripper" wells located in Appalachia and

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[1] Crude oil production has traditionally been expressed in barrels. A barrel is equivalent to 5.61 ft^3, 0.158 m^3, or 42 U.S. gallons.

[2] These numbers, provided to EPA by the Bureau of Land Management (BLM), are generally accepted.

the more developed portions of the rest of the country.[3] Overall, 70 percent of all U.S. oil wells are strippers, operating on the margins of profitability. Together, however, these strippers contribute 14 percent of total U.S. production--a number that appears small, yet is roughly the equivalent of the immense Prudhoe Bay field in Alaska.

Such statistics make it clear that a short discussion such as this cannot provide a comprehensive or fully accurate description of this industry. The purpose of this chapter is simply to present the terminology used in the rest of this report[4] and to provide an overview of typical exploration, development, and production methods. With this as introduction, the chapter then defines which oil and gas wastes EPA considers to be exempt within the scope of RCRA Section 8002; estimates the volumes of exempt wastes generated by onshore oil and gas operations; and presents the results of sample surveys conducted by EPA and the American Petroleum Institute to characterize the content of exempt oil and gas wastes.

Exploration and Development

Although geological and geophysical studies provide information concerning potential accumulations of petroleum, the only method that can confirm the presence of petroleum is exploratory drilling. The majority of exploratory wells are "dry" and must be plugged and abandoned. When an exploratory well does discover a commercial deposit, however, many development wells are typically needed to extract oil or gas from that reservoir.

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3 The definition of "stripper" well may vary from State to State. For example, North Dakota defines a stripper as a well that produces 10 barrels per day or less at 6,000 feet or less; 11 to 15 barrels per day from a depth of 6,001 feet to 10,000 feet; and 16 to 20 barrels per day for wells that are 10,000 feet deep.

4 A glossary of terms is also provided in Volume 3.

Exploratory and development wells are mechanically similar and generate similar wastes up to the point of production. In order to bring a field into production, however, development wells generate wastes associated with well completion and stimulation; these processes are discussed below. From 1981 to 1985, exploration and development drilling combined averaged 73,000 wells per year (API 1986). Drilling activity declined in 1986 and by mid-1987 rebounded over 1986 levels.

In the early part of the century, cable-tool drilling was the predominant method of well drilling. The up-and-down motion of a chisel-like bit, suspended by a cable, causes it to chip away the rock, which must be periodically removed with a bailer. Although an efficient technique, cable-tool drilling is limited to use in shallow, low-pressure reservoirs. Today, cable-tool drilling is used on a very limited basis in the United States, having been replaced almost entirely by rotary drilling.

Rotary drilling provides a safe method for controlling high-pressure oil/gas/water flows and allows for the simultaneous drilling of the well and removal of cuttings, making it possible to drill wells over 30,000 feet deep. Figure II-1 illustrates the process. The rotary motion provided by mechanisms on the drill rig floor turns a drill pipe or stem, thereby causing a bit on the end of the pipe to gouge and chip away the rock at the bottom of the hole. The bit itself generally has three cone-shaped wheels tipped with hardened teeth and is weighted into place by thick-walled collars. Well casing is periodically cemented into the hole, providing a uniform and stable conduit for the drill stem as it drills deeper into the hole. The casing also seals off freshwater aquifers, high-pressure zones, and other troublesome formations.

Most rotary drilling operations employ a circulation system using a water- or oil-based fluid, called "mud" because of its appearance. The

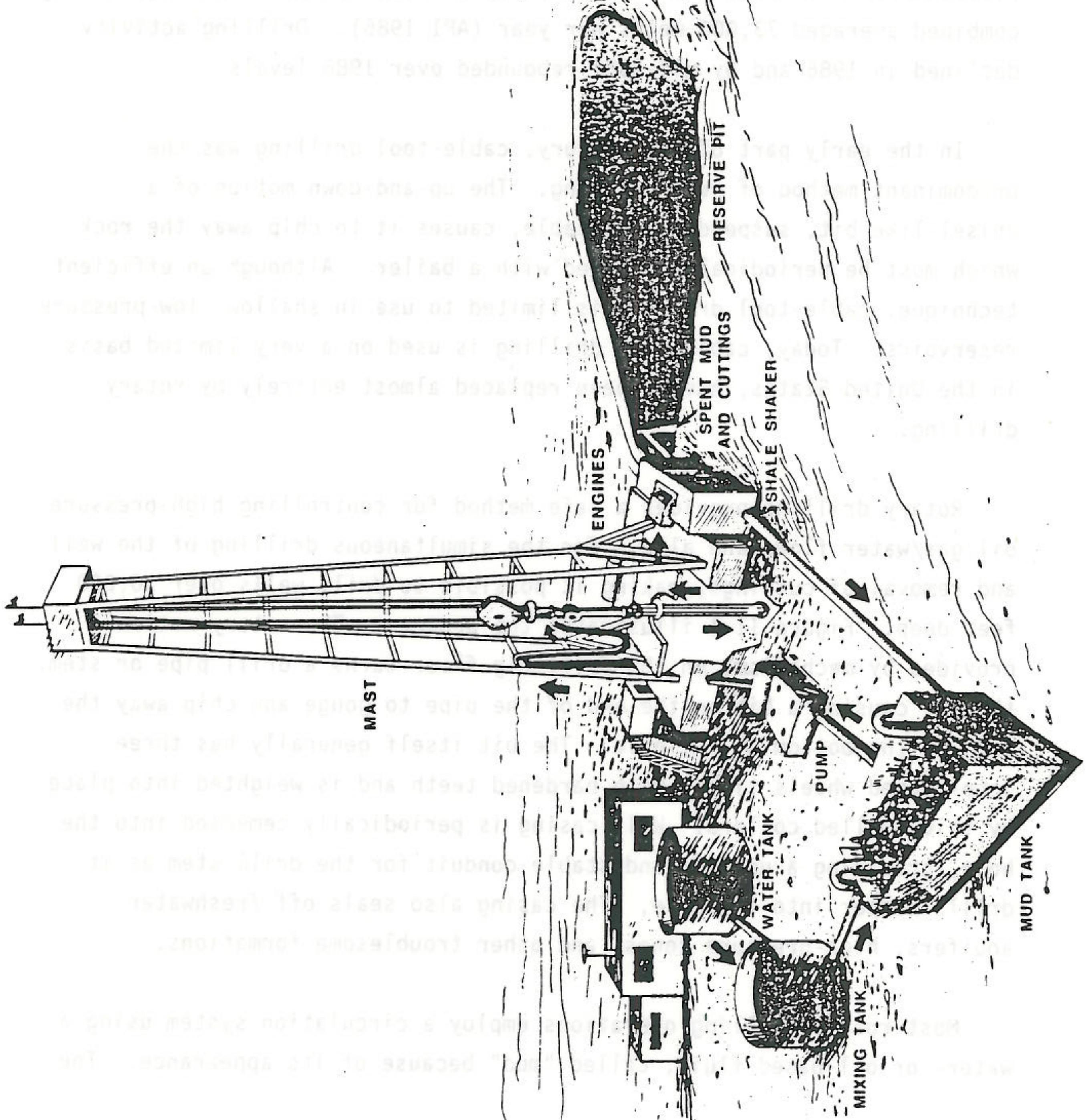

Figure II-1 Typical Rotary Drilling Rig

mud is pumped down the hollow drill pipe and across the face of the bit to provide lubrication and remove cuttings. The mud and cuttings are then pumped back up through the annular space between the drill pipe and the walls of the hole or casing. Mud is generally mixed with a weighting agent such as barite, and other mud additives, thus helping it serve several other important functions: (1) stabilizing the wellbore and preventing cave-ins, (2) counterbalancing any high-pressure oil, gas, or water zones in the formations being drilled, and (3) providing a medium to alleviate problems "downhole" (such as stuck pipe or lost circulation).

Cuttings are removed at the surface by shale shakers, desanders, and desilters; they are then deposited in the reserve pit excavated or constructed next to the rig. The reclaimed drilling mud is then recirculated back to the well. The type and extent of solids control equipment used influences how well the cuttings can be separated from the drilling fluid, and hence influences the volume of mud discharged versus how much is recirculated. Drilling mud must be disposed of when excess mud is collected, when changing downhole conditions require a whole new mud formulation, or when the well is abandoned. The reserve pit is generally used for this purpose. (Reserve pits serve multiple waste management functions. See discussion in Chapter III.) If the well is a dry hole, the drilling mud may be disposed of downhole upon abandonment.

The formation of a drilling mud for a particular job depends on types of geologic formations encountered, economics, availability, problems encountered downhole, and well data collection practices. Water-based drilling muds predominate in the United States. Colloidal materials, primarily bentonitic clay, and weighting materials, such as barite, are common constituents. Numerous chemical additives are available to give the mud precise properties to facilitate the drilling of the well; they include acids and bases, salts, corrosion inhibitors, viscosifiers,

dispersants, fluid loss reducers, lost circulation materials, flocculants, surfactants, biocides, and lubricants. (See also Table III-2.)

Oil-based drilling fluids account for approximately 3 to 10 percent of the total volume of drilling fluids used nationwide. The oil base may consist of crude oil, refined oil (usually fuel oil or diesel), or mineral oil. Oil-based drilling fluid provides lubrication in directionally drilled holes, high-temperature stability in very deep holes, and protection during drilling through water-sensitive formations.

In areas where high-pressure or water-bearing formations are not anticipated, air drilling is considerably faster and less expensive than drilling with water- or oil-based fluids. (Air drilling cannot be used in deep wells.) In this process, compressed air takes the place of mud, cooling the bit and lifting the cuttings back to the surface. Water is injected into the return line for dust suppression, creating a slurry that must be disposed of. In the United States, air drilling is most commonly used in the Appalachian Basin, in southeastern Kansas/northeastern Oklahoma, and in the Four Corners area of the Southwest. Other low-density drilling fluids are used in special situations. Gases other than air, usually nitrogen, are sometimes useful. These may be dispersed with liquids or solids, creating wastes in the form of mist, foam, emulsion, suspension, or gel.

Potential producing zones are commonly measured and analyzed (logged) during drilling, a process that typically generates no waste. If hydrocarbons appear to be present, a drill stem test can tell much about their characteristics. When the test is completed, formation fluids collected in the drill pipe must be disposed of.

If tests show that commercial quantities of oil and gas are present, the well must be prepared for production or "completed." "Cased hole"

completions are the most common type. First, production casing is run into the hole and cemented permanently in place. Then one or more strings of production tubing are set in the hole, productive intervals are isolated with packers, and surface equipment is installed. Actual completion involves the use of a gun or explosive charge that perforates the production casing and begins the flow of petroleum into the well.

During these completion operations, drilling fluid in the well may be modified or replaced by specialized fluids to control flow from the formation. A typical completion fluid consists of a brine solution modified with petroleum products, resins, polymers, and other chemical additives. When the well is produced initially, the completion fluid may be reclaimed or treated as a waste product that must be disposed of. For long-term corrosion protection, a packer fluid is placed into the casing/tubing annulus. Solids-free diesel oil, crude oil, produced water, or specially treated drilling fluid are preferred packer fluids.

Following well completion, oil or gas in the surrounding formations frequently is not under sufficient pressure to flow freely into the well and be removed. The formation may be impacted with indigenous material, the area directly surrounding the borehole may have become packed with cuttings, or the formation may have inherent low permeability.

Operators use a variety of stimulation techniques to correct these conditions and increase oil flow. Acidizing introduces acid into the production formation, dissolving formation matrix and thereby enlarging existing channels in carbonate-bearing rock. Hydraulic fracturing involves pumping specialized fluids carrying sand, glass beads, or similar materials into the production formation under high pressure; this creates fractures in the rock that remain propped open by the sand, beads, or similar materials when pressure is released.

Other specialized fluids may be pumped down a production well to enhance its yield; these can include corrosion inhibitors, surfactants, friction reducers, complexing agents, and cleanup additives. Although the formation may retain some of these fluids, most are returned to the surface when the well is initially produced or are slowly released over time. These fluids may require disposal, independent of disposal associated with produced water.

Drilling operations have the potential to create air pollution from several sources. The actual drilling equipment itself is typically run by large diesel engines that tend to emit significant quantities of particulates, sulfur oxides, and oxides of nitrogen, which are subject to regulation under the Clean Air Act. The particulates emitted may contain heavy metals as well as polycyclic organic matter (POMs). Particularly for deep wells, which require the most power to drill, and in large fields where several drilling operations may be in progress at the same time, cumulative diesel emissions can be important. Oil-fired turbines are also used as a source of power on newer drilling rigs. Other sources of air pollution include volatilization of light organic compounds from reserve pits and other holding pits that may be in use during drilling; these are exempt wastes. These light organics can be volatilized from recovered hydrocarbons or from solvents or other chemicals used in the production process for cleaning, fracturing, or well completion. The volume of volatile organic compounds is insignificant in comparison to diesel engine emissions.

Production

Production operations generally include all activities associated with the recovery of petroleum from geologic formations. They can be divided into activities associated with downhole operations and activities associated with surface operations. Downhole operations include primary, secondary, and tertiary recovery methods; well workovers; and well stimulation activities. Activities associated with

surface operations include oil/gas/water separation, fluid treatment, and disposal of produced water. Each of these terms is discussed briefly below.

Downhole Operations

Primary recovery refers to the initial production of oil or gas from a reservoir using natural pressure or artificial lift methods, such as surface or subsurface pumps and gas lift, to bring it out of the formation and to the surface. Most reservoirs are capable of producing oil and gas by primary recovery methods alone, but this ability declines over the life of the well. Eventually, virtually all wells must employ some form of secondary recovery, typically involving injection of gas or liquid into the reservoir to maintain pressure within the producing formation. Waterflooding is the most frequently employed secondary recovery method. It involves injecting treated fresh water, seawater, or produced water into the formation through a separate well or wells.

Tertiary recovery refers to the recovery of the last portion of the oil that can be economically produced. Chemical, physical, and thermal methods are available and may be used in combination. Chemical methods involve injection of fluids containing substances such as surfactants and polymers. Miscible oil recovery involves injection of gases, such as carbon dioxide and natural gas, which combine with the oil. Thermal recovery methods include steam injection and in situ combustion (or "fire flooding"). When oil eventually reaches a production well, injected gases or fluids from secondary and tertiary recovery operations may be dissolved or carried in formation oil or water, or simply mixed with them; their removal is discussed below in conjunction with surface production operations.

Workovers, another aspect of downhole production operations, are designed to restore or increase production from wells whose flows are

inhibited by downhole mechanical failures or blockages, such as sand or paraffin deposits. Fluids circulated into the well for this purpose must be compatible with the formation and must not adversely affect permeability. They are similar to completion fluids, described earlier. When the well is put back into production, the workover fluid may be reclaimed or disposed of.

Other chemicals may be periodically or continuously pumped down a production well to inhibit corrosion, reduce friction, or simply keep the well flowing. For example, methanol may be pumped down a gas well to keep it from becoming plugged with ice.

Surface Operations

Surface production operations generally include gathering of the produced fluids (oil, gas, gas liquids, and water) from a well or group of wells and separation and treatment of the fluids. See Figures II-2, II-3, and II-4. As producing reservoirs are depleted, their water/oil ratios may increase steeply. New wells may produce little if any water; stripper wells may vary greatly in the volume of water they produce. Some may produce more than 100 barrels of water for every barrel of oil, particularly if the wells are subject to waterflooding operations.

Virtually all of this water must be removed before the product can be transferred to a pipeline. (The maximum water content allowed is generally less than 1 percent.) The oil may also contain completion or workover fluids, stimulation fluids, or other chemicals (biocides, fungicides) used as an adjunct to production. Some oil/water mixtures may be easy to separate, but others may exist as fine emulsions that do

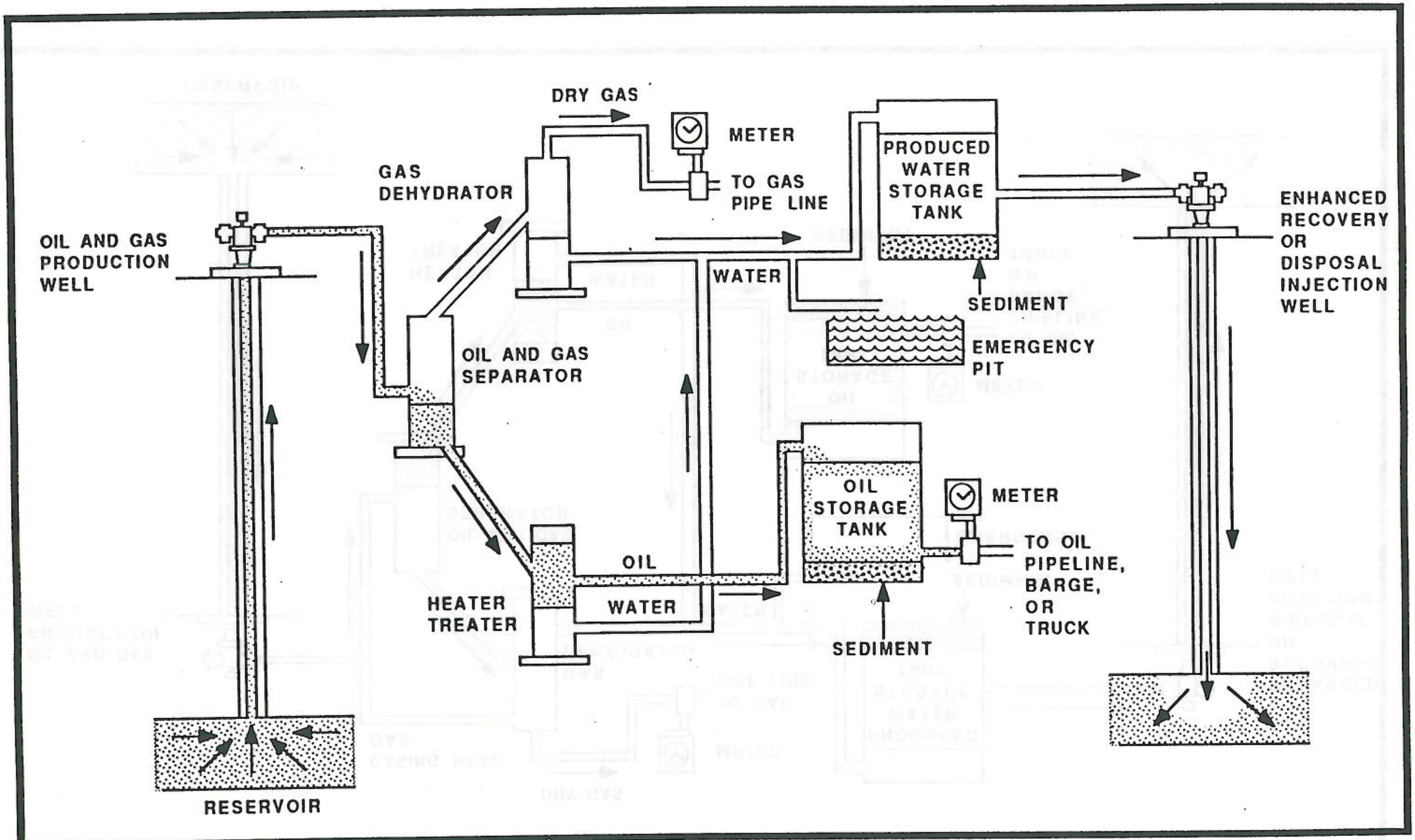

Figure II-2 Typical Production Operation, Showing Separation of Oil, Gas, and Water

Produced waters are not always injected as indicated in this figure. Produced water may be trucked to central treatment and disposal facilities, discharged into disposal pits, discharged to surface or coastal waters, or used for beneficial or agricultural use.

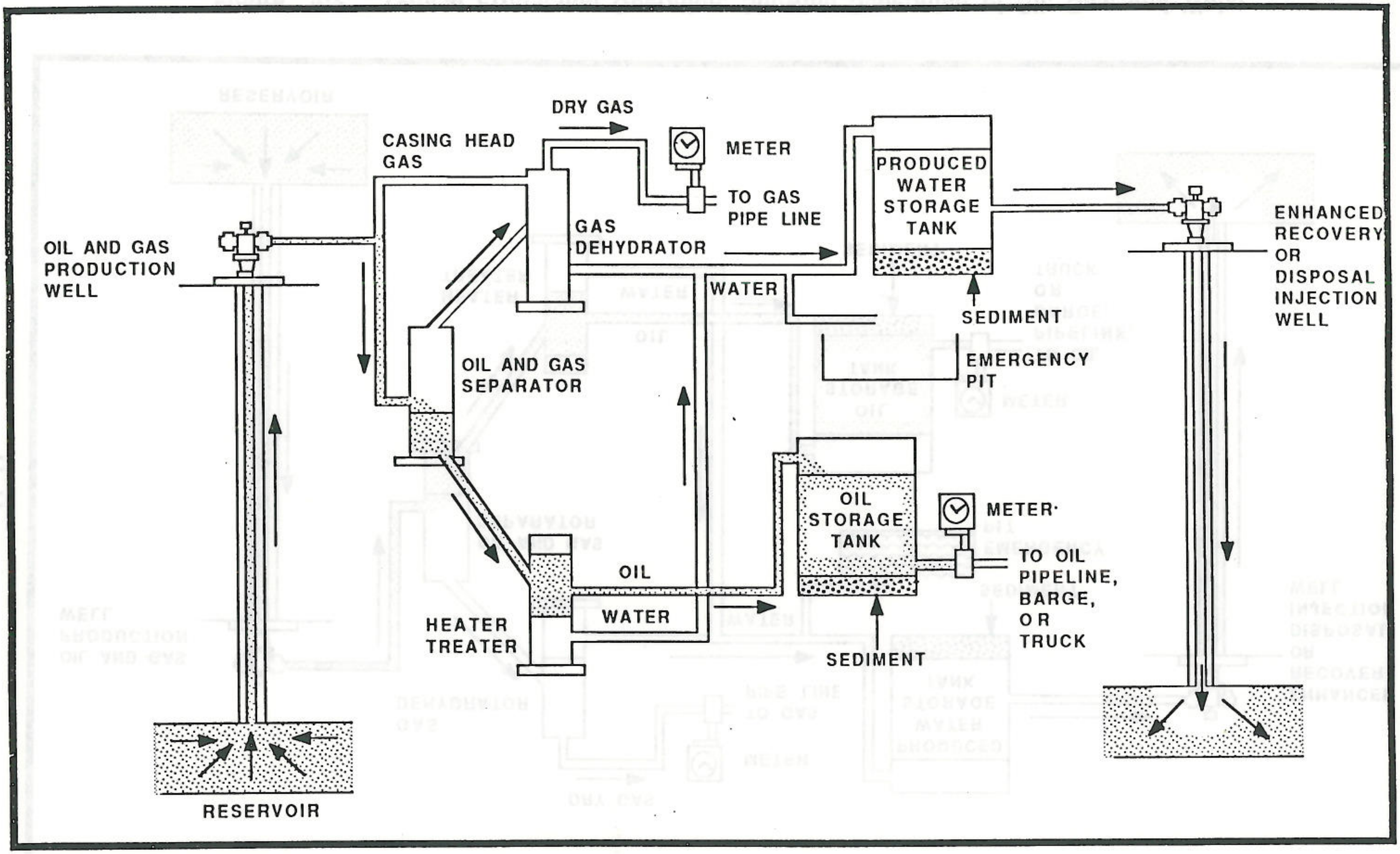

Figure II-3 Oil Production With Average H_2O Production With Dissolved/Associated Gas

Produced waters are not always injected as indicated in this figure. Produced water may be trucked to central treatment and disposal facilities, discharged into disposal pits, discharged to surface or coastal waters, or used for beneficial or agricultural use.

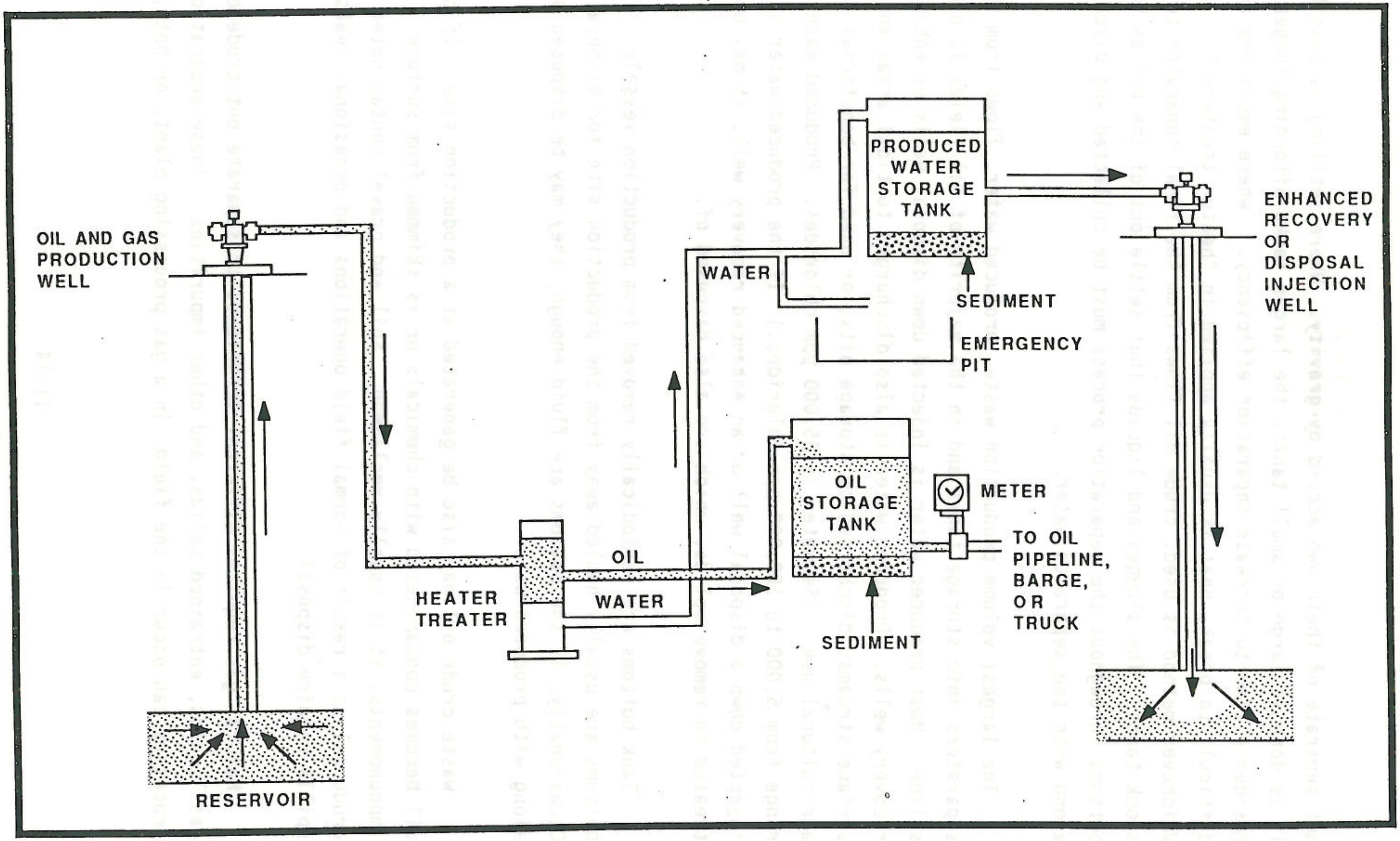

Figure II-4 High Oil/H_2O Ratio Without Significant Dissolved/Associated Gas

Produced waters are not always injected as indicated in this figure. Produced water may be trucked to central treatment and disposal facilities, discharged into disposal pits, discharged to surface or coastal waters, or used for beneficial or agricultural use.

not separate of their own accord by gravity. Where settling is possible, it is done in large or small tanks, the larger tanks affording longer residence time to increase separation efficiency. Where emulsions are difficult to break, heat is usually applied in "heater treaters." Whichever method is used, crude oil flows from the final separator to stock tanks. The sludges and liquids that settle out of the oil as tank bottoms throughout the separation process must be collected and discarded along with the separated water.

The largest volume production waste, produced water, flows from the separators into storage tanks and in the majority of oil fields is highly saline. Most produced water is injected down disposal wells or enhanced recovery wells. Produced water is also discharged to tidal areas and surface streams, discharged to storage pits, or used for beneficial or agricultural use. (Seawater is 35,000 ppm chlorides. Produced water can range from 5,000 to 180,000 ppm chlorides.) If the produced water is injected down a disposal well or an enhanced recovery well, it may be treated to remove solids, which are also disposed of.

Tank bottoms are periodically removed from production vessels. Tank bottoms are usually hauled away from the production site for disposal. Occasionally, if the bottoms are fluid enough, they may be disposed of along with produced water.

Waste crude oil may also be generated at a production site. If crude oil becomes contaminated with chemicals or is skimmed from surface impoundments, it is usually reclaimed. Soil and gravel contaminated by crude oil as a result of normal field operations and occasional leaks and spills require disposal.

Natural gas requires different techniques to separate out crude oil, gas liquids, entrained solids, and other impurities. These separation processes can occur in the field, in a gas processing plant, or both, but

more frequently occur at an offsite processing plant. Crude oil, gas liquids, some free water, and entrained solids can be removed in conventional separation vessels. More water may be removed by any of several dehydration processes, frequently through the use of glycol, a liquid dessicant, or various solid dessicants. Although these separation media can generally be regenerated and used again, they eventually lose their effectiveness and must be disposed of.

Both crude oil and natural gas may contain the highly toxic gas hydrogen sulfide, which is an exempt waste. (Eight hundred ppm in air is lethal to humans and represents an occupational hazard, but not an ambient air toxics threat to human health offsite.) At plants where hydrogen sulfide is removed from natural gas, sulfur dioxide (SO_2) release results. (EPA requires compliance with the National Ambient Air Quality Standards (NAAQS) for sulfur dioxide; DOI also has authority to regulate these emissions.) Sulfur is often recovered from the hydrogen sulfide (H_2S) as a commercial byproduct. H_2S dissolved in crude oil does not pose any danger, but when it is produced at the wellhead in gaseous form, it poses serious occupational risks through possible leaks or blowouts. These risks are also present later in the production process when the H_2S is separated out in various "sweetening" processes. The amine, iron sponge, and selexol processes are three examples of commercial processes for removing acid gases from natural gas. Each H_2S removal process results in spent or waste separation media, which must be disposed of. EPA did not sample hydrogen sulfide and sulphur dioxide emissions because of their relatively low volume and infrequency of occurrence.

Gaseous wastes are generated from a variety of other production-related operations. Volatile organic compounds may also be released from minute leaks in production equipment or from pressure vents on separators and storage tanks. When a gas well needs to be cleaned out, it may be produced wide open and vented directly to the atmosphere.

Emissions from volatile organic compounds are exempt under Section 3001(b)(2)(A) of RCRA and represent a very low portion of national air emissions. Enhanced oil recovery steam generators may burn crude oil as fuel, thereby creating air emissions. These wastes are nonexempt.

DEFINITION OF EXEMPT WASTES

The following discussion presents EPA's tentative definition of the scope of the exemption.

Scope of the Exemption

The current statutory exemption originated in EPA's proposed hazardous waste regulations of December 18, 1978 (43 FR 58946). Proposed 40 CFR 250.46 contained standards for "special wastes"--reduced requirements for several types of wastes that are produced in large volume and that EPA believed may be lower in toxicity than other wastes regulated as hazardous wastes under RCRA. One of these categories of special wastes was "gas and oil drilling muds and oil production brines."

In the RCRA amendments of 1980, Congress exempted most of these special wastes from the hazardous waste requirements of RCRA Subtitle C, pending further study by EPA. The oil and gas exemption, Section 3001(b)(2)(A), is directed at "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas." The legislative history does not elaborate on the definition of drilling fluids or produced waters, but it does discuss "other wastes" as follows:

> The term "other wastes associated" is specifically included to designate waste materials intrinsically derived from the primary field operations associated with the exploration, development, or production of crude oil and natural gas. It would cover such substances as: hydrocarbon bearing soil in and around related facilities; drill cuttings; and materials (such as hydrocarbons,

water, sand and emulsion) produced from a well in conjunction with crude oil and natural gas and the accumulated material (such as hydrocarbons, water, sand, and emulsion) from production separators, fluid treating vessels, storage vessels, and production impoundments. (H.R. Rep No. 1444, 96th Cong., 2d Sess. at 32 (1980)).

The phrase "intrinsically derived from the primary field operations..." is intended to differentiate exploration, development, and production operations from transportation (from the point of custody transfer or of production separation and dehydration) and manufacturing operations.

In order to arrive at a clear working definition of the scope of the exemption under Section 8002(m), EPA has used these statements in conjunction with the statutory language of RCRA as a basis for making the following assumptions about which oil and gas wastes should be included in the present study.

- Although the legislative history underlying the oil and gas exemption is limited to "other wastes associated with the exploration development or production of crude oil or natural gas," the Agency believes that the rationale set forth in that history is equally applicable to produced waters and drilling fluids. Therefore, in developing criteria to define the scope of the Section 3001(b)(2) exemption, the Agency has applied this legislative history to produced waters and drilling fluids.

- The potential exists for small volume nonexempt wastes to be mixed with exempt wastes, such as reserve pit contents. EPA believes it is desirable to avoid improper disposal of hazardous (nonexempt) wastes through dilution with nonhazardous exempt wastes. For example, unused pipe dope should not be disposed of in reserve pits. Some residual pipe dope, however, will enter the reserve pit as part of normal field operations; this residual pipe dope does not concern EPA. EPA is undecided as to the proper disposal method for some other waste streams, such as rigwash that often are disposed of in reserve pits.

Using these assumptions, the test of whether a particular waste qualifies under the exemption can be made in relation to the following three separate criteria. No one criterion can be used as a standard when defining specific waste streams that are exempt. These criteria are as follows.

1. Exempt wastes must be associated with measures (1) to locate oil or gas deposits, (2) to remove oil or natural gas from the ground, or (3) to remove impurities from such substances, provided that the purification process is an integral part of primary field operations.[5]

2. Only waste streams intrinsic to the exploration for, or the development and production of, crude oil and natural gas are subject to exemption. Waste streams generated at oil and gas facilities that are not uniquely associated with the exploration, development, or production activities are not exempt. (Examples would include spent solvents from equipment cleanup or air emissions from diesel engines used to operate drilling rigs.)

   Clearly those substances that are extracted from the ground or injected into the ground to facilitate the drilling, operation, or maintenance of a well or to enhance the recovery of oil and gas are considered to be uniquely associated with primary field operations. Additionally, the injection of materials into the pipeline at the wellhead which keep the lines from freezing or which serve as solvents to prevent paraffin accumulation is intrinsically associated with primary field operations. With regard to injection for enhanced recovery, the injected materials must function primarily to enhance recovery of oil and gas and must be recognized by the Agency as being appropriate for enhanced recovery. An example would be produced water. In this context, "primarily functions" means that the main reason for injecting the materials is to enhance recovery of oil and gas rather than to serve as a means for disposing of those materials.

3. Drilling fluids, produced waters, and other wastes intrinsically derived from primary field operations associated with the exploration, development, or production of crude oil, natural gas, or geothermal energy are subject to exemption. Primary field operations encompass production-related activities but not transportation or manufacturing activities. With respect to oil production, primary field operations encompass those activities occurring at or near the wellhead, but prior to the transport of oil from an individual field facility or a centrally located facility to a carrier (i.e., pipeline or trucking concern) for transport to a refinery or to a refiner. With respect to natural gas production, primary field operations are those activities occurring at or near the wellhead or at the gas plant but prior to that point at which the gas is transferred from an individual field facility, a centrally located facility, or a gas plant to a carrier for transport to market.

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5 Thus, wastes associated with such processes as oil refining, petrochemical-related manufacturing, or electricity generation are not exempt because those processes do not occur at the primary field operations.

Primary field operations may encompass the primary, secondary, and tertiary production of oil or gas. Wastes generated by the transportation process itself are not exempt because they are not intrinsically associated with primary field operations. An example would be pigging waste from pipeline pumping stations.

Transportation for the oil and gas industry may be for short or long distances. Wastes associated with manufacturing are not exempt because they are not associated with exploration, development, or production and hence are not intrinsically associated with primary field operations. Manufacturing (for the oil and gas industry) is defined as any activity occurring within a refinery or other manufacturing facility the purpose of which is to render the product commercially saleable.

Using these definitions, Table II-1 presents definitions of exempted wastes as defined by EPA for the purposes of this study. Note that this is a partial list only. Although it includes all the major streams that EPA has considered in the preparation of this report, others may exist. In that case, the definitions listed above would be applied to determine their status under RCRA.

Waste Volume Estimation Methodology

Information concerning volumes of wastes from oil and gas exploration, development, and production operations is not routinely collected nationwide, making it necessary to develop methods for estimating these volumes by indirect methods in order to comply with the Section 8002(m) requirement to present such estimates to Congress. For this study, estimates were compiled independently by EPA and by the American Petroleum Institute (API) using different methods. Both are discussed below.

Estimating Volumes of Drilling Fluids and Cuttings

EPA considered several different methodologies for determining volume estimates for produced water and drilling fluid.

Table II-1 Partial List of Exempt and Nonexempt Wastes

EXEMPT WASTES

Drill cuttings

Drilling fluids

Well completion, treatment, and stimulation fluids

Packing fluids

Sand, hydrocarbon solids, and other deposits removed from production wells

Pipe scale, hydrocarbon solids, hydrates, and other deposits removed from piping and equipment

Hydrocarbon-bearing soil

Pigging wastes from gathering lines

Wastes from subsurface gas storage and retrieval

Basic sediment and water and other tank bottoms from storage facilities and separators

Produced water

Constituents removed from produced water before it is injected or otherwise disposed of

Accumulated materials (such as hydrocarbons, solids, sand, and emulsion) from production separators, fluid-treating vessels, and production impoundments that are not mixed with separation or treatment media

Drilling muds from offshore operations

Appropriate fluids injected downhole for secondary and tertiary recovery operations

Liquid hydrocarbons removed from the production stream but not from oil refining

Gases removed from the production stream, such as hydrogen sulfide, carbon dioxide, and volatilized hydrocarbons

Materials ejected from a production well during the process known as blowing down a well

Waste crude oil from primary field operations

Light organics volatilized from recovered hydrocarbons or from solvents or other chemicals used for cleaning, fracturing, or well completion

NONEXEMPT WASTES

Waste lubricants, hydraulic fluids, motor oil, and paint

Waste solvents from clean-up operations

Off-specification and unused materials intended for disposal

Incinerator ash

Pigging wastes from transportation pipelines

Sanitary wastes, trash, and gray water

Gases, such as SOx, NOx, and particulates from gas turbines or other machinery

Drums (filled, partially filled, or cleaned) whose contents are not intended for use

Waste iron sponge, glycol, and other separation media

Filters

Spent catalysts

Wastes from truck- and drum-cleaning operations

Waste solvents from equipment maintenance

Spills from pipelines or other transport methods

Table II-1

EPA's estimates: For several regions of the country, estimates of volumes of drilling fluids and cuttings generated from well drilling operations are available on the basis of waste volume per foot of well drilled. Estimates range from 0.2 barrel/foot (provided by the West Virginia Dept. of Natural Resources) to 2.0 barrels/foot (provided by NL Baroid Co. for Cotton Valley formation wells in Panola County, Texas). EPA therefore considered the possibility of using this approach nationwide. If it were possible to generate such estimates for all areas of the country, including allowances for associated wastes such as completion fluids and waste cement, nationwide figures would then be comparatively easy to generate. They could be based on the total footage of all wells drilled in the U.S., a statistic that is readily available from API.

This method proved infeasible, however, because of a number of complex factors contributing to the calculation of waste-per-foot estimates that would be both comprehensive and valid for all areas of the country. For instance, the use of solids control equipment at drilling sites, which directly affects waste generation, is not standardized. In addition, EPA would have to differentiate among operations using various drilling fluids (oil-based, water-based, and gas-based fluids). These and other considerations caused the Agency to reject this method of estimating volumes of drilling-related wastes.

Another methodology would be to develop a formal model for estimating waste volumes based on all the factors influencing the volume of drilling waste produced. These factors would include total depth drilled, geologic formations encountered, drilling fluid used, solids control equipment used, drilling problems encountered, and so forth. Such a model could then be applied to a representative sample of wells drilled nationwide, yielding estimates that could then be extrapolated to produce nationwide volumes estimates.

This method, too, was rejected as infeasible. It would have required access to data derived from the driller's logs and mud logs maintained at individual well sites, which would have been very difficult to acquire. Beyond this, other data and analytical needs for building such a model proved to be beyond the resources available for the project.

With these methodologies unavailable, EPA developed its estimates by equating the wastes generated from a drilling operation with the volume of the reserve pit constructed to service the well. Typically, each well is served by a single reserve pit, which is used primarily for either temporary or permanent disposal of drilling wastes. Based on field observations, EPA made the explicit assumption that reserve pits are sized to accept the wastes anticipated from the drilling operation. The Agency then collected information on pit sizes during the field sampling program in 1986 (discussed later in this chapter), from literature searches, and by extensive contact with State and Federal regulatory personnel.

EPA developed three generic pit sizes (1,984-, 22,700-, and 87,240-barrel capacity) to represent the range of existing pits and assigned each State a percent distribution for each pit size based on field observation and discussion with selected State and industry personnel. For example, from the data collected, Utah's drilling sites were characterized as having 35 percent small pits, 50 percent medium pits, and 15 percent large pits. Using these State-specific percent distributions, EPA was then able to readily calculate an estimate of annual drilling waste volumes per year for each State. Because Alaska's operations are generally larger than operations in the other oil- and gas-producing States, Alaska's generic pit sizes were different (55,093- and 400,244-barrel capacity.)

Although the EPA method is relatively simple, relying on a well site feature that is easily observable (namely, the reserve pit), the method does have several disadvantages. It does not explicitly account for waste volume increases and decreases due to evaporation, percolation, and rainwater collection. The three generic pit sizes may not adequately represent the wide range of pit sizes used for drilling, and they all assume that the total volume of each reserve pit, minus a nominal 2 feet of freeboard, will be used for wastes. Finally, the information collected to determine the percent distributions of pit sizes within States may not adequately characterize the industry, and adjusting the distribution would require gathering new information or taking a new survey. All of these uncertainties detract from the accuracy of a risk assessment or an economic impact analysis used to evaluate alternative waste management techniques.

The American Petroleum Institute's estimates: As the largest national oil trade organization, the API routinely gathers and analyzes many types of information on the oil and gas industry. In addition, in conducting its independent estimates of drilling waste volumes, API was able to conduct a direct survey of operators in 1985 to request waste volume data--a method that was unavailable to EPA because of time and funding limitations. API sent a questionnaire to a sample of operators nationwide, asking for estimated volume data for drilling muds and completion fluids, drill cuttings, and other associated wastes discharged to the reserve pit. Completed questionnaires were received for 693 individual wells describing drilling muds, completion fluids, and drill cuttings; 275 questionnaires also contained useful information concerning associated wastes. API segregated the sampled wells so that it could characterize drilling wastes within each of 11 sampling zones used in this study and within each of 4 depth classes. Since API maintains a data base on basic information on all wells drilled in the U.S., including location and depth, it was able to estimate a volume of wastes for the more than 65,000 wells drilled in 1985. The API survey does have

several significant limitations. Statistical representativeness of the survey is being analyzed by EPA. Respondents to the survey were primarily large oil companies. The survey was accompanied by a letter that may have influenced the responses. Also, EPA experience with operators indicates that they may underestimate reserve pit volumes.

Even though volumetric measurement and statistical analysis represent the preferred method for estimating drilling waste volumes, the way in which API's survey was conducted and the data were analyzed may have some drawbacks. Operators were asked to estimate large volumes of wastes, which are added slowly to the reserve pit and are not measured. Because the sample size is small in comparison to the population, it is questionable whether the sample is an unbiased representation of the drilling industry.

Estimating Volumes of Produced Water

By far the largest volume production waste from oil and gas operations is produced water. Of all the wastes generated from oil and gas operations, produced water figures are reported with the most frequency because of the reporting requirements under the Underground Injection Control (UIC) and National Pollution Discharge Elimination System (NPDES) programs.

EPA's estimates: Because produced water figures are more readily available than drilling waste data, EPA conducted a survey of the State agencies of 33 oil- and gas-producing States, requesting produced water data from injection reports, production reports, and hauling reports. For those States for which this information was not available, EPA derived estimates calculated from the oil/water ratio from surrounding States (this method used for four States) or derived estimates based on information provided by State representatives (this method used for six States).

API's estimates: In addition to its survey of drilling wastes, API conducted a supplemental survey to determine total volumes of produced water on a State-by-State basis. API sent a produced water survey form to individual companies requesting 1985 crude oil and condensate volumes and produced water volumes and distribution. Fourteen operators in 23 States responded. Because most of the operators were active in more than one State, API was able to include a total of 170 different survey points. API then used these data to generate water-to-oil ratios (number of barrels of water produced with each barrel of oil) for each operator in each State. By extrapolation, the results of the survey yield an estimate of the total volume of produced water on a statewide basis; the statewide estimated produced water volume total is simply the product of the estimated State ratio (taken from this survey) and the known total oil production for the State. API reports this survey method to have a 95 percent confidence level for produced water volumes. No standard deviation was reported with this confidence level.

For most States, the figure generated by this method agrees closely with the figure arrived at by EPA in its survey of State agencies in 33 oil-producing States. For a few States, however, the EPA and API numbers are significantly different; Wyoming is an example. Since most of the respondents to the API survey were major companies, their production operations may not be truly representative of the industry as a whole. Also, the API method did not cover all of the States covered by EPA.

Neither method can be considered completely accurate, so judgment is needed to determine the best method to apply for each State. Because the Wyoming State agency responsible for oil and gas operations believes that the API number is greatly in error, the State number is used in this report. Also, since the API survey did not cover many of the States in the Appalachian Basin, the EPA numbers for all of the Appalachian Basin States are used here. In all other cases, however, the API-produced water volume numbers, which were derived in part from a field survey, are believed to be more accurate than EPA numbers and are therefore used in this report.

Waste Volume Estimates

Drilling waste volumes for 1985, calculated by both the EPA and API methods, appear in Table II-2. Although the number of wells drilled for each State differs between the two methods, both methods fundamentally relied upon API data. The EPA method estimates that 2.44 billion barrels of waste were generated from the drilling of 64,508 wells, for an average of 37,902 barrels of waste per well. The API method estimates that 361 million barrels of waste were generated from the drilling of 69,734 wells, for an average of 5,183 barrels of waste per well. EPA has reviewed API's survey methodology and believes the API method is more reliable in predicting actual volumes generated. For the purposes of this report, EPA will use the API estimates for drilling waste volumes.

Produced water volumes for 1985, calculated by both the EPA and API methods, appear in Table II-3. The EPA method estimates 11.7 billion barrels of produced water. The API method estimates 20.9 billion barrels of produced water.

CHARACTERIZATION OF WASTES

In support of this study, EPA collected samples from oil and gas exploration, development, and production sites throughout the country and analyzed them to determine their chemical composition. The Agency designed the sampling plan to ensure that it would cover the country's wide range of geographic and geologic conditions and that it would randomly select individual sites for study within each area (USEPA 1987). One hundred one samples were collected from 49 sites in 26 different locations. Operations sampled included centralized treatment facilities, central disposal facilities, drilling operations, and production facilities. For a more detailed discussion of all aspects of EPA's sampling program, see USEPA 1987.

Table II-2 Estimated U.S. Drilling Waste Volumes, 1985

State	EPA method Number of wells drilled	Volume[a] 1,000 bbl	API method Number of wells drilled	Volume[b] 1,000 bbl
Alabama	343	15,179	367	5,994
Alaska	206	4,118	242	1,816
Arizona	3	56	3	23
Arkansas	975	43,147	1,034	8,470
California	3,038	82,276	3,208	4,529
Colorado	1,459	27,249	1,578	8,226
Florida	21	929	21	1,068
Georgia	NC[c]	NC	1	2
Idaho	NC	NC	3	94
Illinois	2,107	57,063	2,291	2,690
Indiana	910	24,645	961	1,105
Iowa	NC	NC	1	1
Kansas	5,151	96,818	5,560	17,425
Kentucky	2,141	8,683	2,482	4,874
Louisiana	4,645	205,954	4,908	46,726
Maryland	85	345	91	201
Michigan	823	22,289	870	3,866
Mississippi	568	25,136	594	14,653
Missouri	22	596	23	18
Montana	591	36,302	623	4,569
Nebraska	261	4,906	282	761
Nevada	34	1,070	36	335
New Mexico	1,694	31,638	1,780	13,908
New York	395	1,602	436	1,277
North Dakota	485	9,116	514	4,804
Ohio	3,413	13,842	3,818	8,139
Oklahoma	6,978	383,581	7,690	42,547
Oregon	5	135	5	5
Pennsylvania	2,466	10,001	2,836	8,130

Table II-2 (continued)

State	EPA method Number of wells drilled	EPA method Volume[a] 1,000 bbl	API method Number of wells drilled	API method Volume[b] 1,000 bbl
South Dakota	44	827	49	289
Tennessee	169	685	228	795
Texas	22,538	1,238,914	23,915	133,014
Utah	332	6,201	364	4,412
Virginia	85	345	91	201
Washington	NC[c]	NC[c]	4	15
West Virginia	1,188	4,818	1,419	3,097
Wyoming	1,409[d]	86,546[d]	1,497	13,528
U.S. Total	64,499	2,444,667	69,734	361,406

a Based on total available reserve pit volume, assuming 2 ft of freeboard (ref.).
b Based on total volume of drilling muds, drill cuttings, completion fluids, circulated cement, formation testing fluids, and other water and solids.
c Not calculated.
d EPA notes that for Wyoming, the State's numbers are 1,332 and 11,988,000, respectively.

Table II-3 Estimated U.S. Produced Water Volumes, 1985

State	EPA volumes 1,000 bbl	Source	API volumes 1,000 bbl	Source
Alabama	34,039	a	87,619	g
Alaska	112,780	b	97,740	g
Arizona	288	b	149	g
Arkansas	226,784	b	184,536	g
California	2,553,326	b	2,846,978	g
Colorado	154,255	d	388,661	g
Florida	85,052	b	64,738	g
Illinois	8,560	e	1,282,933	g
Indiana	5,846	d	--	h
Kansas	1,916,250	f	999,143	g
Kentucky	16,055	d	90,754	g
Louisiana	794,030	f	1,346,675	g
Maryland	0	b	--	h
Michigan	64,046	b	76,440	g
Mississippi	361,038	e	318,666	g
Missouri	2,177	a	--	h
Montana	159,343	b	223,558	g
Nebraska	73,411	b	164,688	g
Nevada	3,693	a	--	h
New Mexico	368,249	e	445,265	g
New York	4,918	e	--	h
North Dakota	88,529	b	59,503	g
Ohio	13,688	e	--	h
Oklahoma	1,627,390	f	3,103,433	g
Oregon	33	b	--	h
Pennsylvania	31,131	f	--	h
South Dakota	3,127	b	5,155	g
Tennessee	800	f	--	h
Texas	2,576,000	e	7,838,783	g
Utah	126,000	e	260,661	g
Virginia	0	b	--	h
West Virginia	7,327	d	2,844	g
Wyoming	253,476*	f	985,221	g
U.S. Total	11,671,641		20,873,243**	

Sources:
- a. Injection Reports
- b. Production Reports
- c. Hauling Reports
- d. Estimate calculated from water/oil ratio from surrounding States
- e. Estimate calculated from water/oil ratio from other years for which data were available
- f. Estimate calculated from information provided by State representative. See Table I-8, (Westec, 1987) to explain footnotes a-f
- g. API industry survey
- h. Not surveyed

* Wyoming states that 1,722,599,614 barrels of produced water were generated in the State in 1985. For the work done in Chapter VI, the State's numbers were used.

** Includes only States surveyed.

Central pits and treatment facilities receive wastes from numerous oil and gas field operations. Since large geographic areas are serviced by these facilities, the facilities tend to be very large; one pit in Oklahoma measured 15 acres and was as deep as 50 feet in places. Central pits are used for long-term waste storage and incorporate no treatment of pit contents. Typical operations accept drilling waste only, produced waters only, or both. Long-term, natural evaporation can concentrate the chemical constituents in the pit. Central treatment and disposal facilities are designed for reconditioning and treating wastes to allow for discharge or final disposal. Like central pits, central treatment facilities can accept drilling wastes only, produced water only, or both.

Reserve pits are used for onsite disposal of waste drilling fluids. These reserve pits are usually dewatered and backfilled. Waste byproducts present at production sites include saltwater brines (called produced waters), tank bottom sludge, and "pigging wax," which can accumulate in the gathering lines.

Extracts from these samples were prepared both directly and following the proposed EPA Toxicity Characteristic Leaching Procedure (TCLP). They were analyzed for organic compounds, metals, classical wet chemistry parameters, and certain other analytes.

API conducted a sampling program concurrent with EPA's. API's universe of sites was slightly smaller than EPA's, but where they overlapped, the results have been compared. API's methodology was designed to be comparable to that used by EPA, but API's sampling and analytical methods, including quality assurance and quality control procedures, varied somewhat from EPA's. These dissimilarities can lead to different analytical results. For a more detailed discussion of all aspects of API's sampling program, see API 1987.

Sampling Methods

Methods used by EPA and by API are discussed briefly below, with emphasis placed on EPA's program.

EPA Sampling Procedures

Pit sampling: All pit samples were composited grab samples. The EPA field team took two composited samples for each pit--one sludge sample and one supernatant sample. Where the pit did not contain a discrete liquid phase, only a sludge sample was taken. Sludge samples are defined by EPA for this report as tank bottoms, drilling muds, or other samples that contains a significant quantity of solids (normally greater than 1 percent). EPA also collected samples of drilling mud before it entered the reserve pit.

Each pit was divided into four quadrants, with a sample taken from the center of each quadrant, using either a coring device or a dredge. The coring device was lined with Teflon or glass to avoid sample contamination. This device was preferred because of its ease of use and deeper penetration. The quadrant samples were then combined to make a single composite sample representative of that pit.

EPA took supernatant samples at each of the four quadrant centers before collecting the sludge samples, using a stainless steel liquid thief sampler that allows liquid to be retrieved from any depth. Samples were taken at four evenly spaced depths between the liquid surface and the sludge-supernatant interface. EPA followed the same procedure at each of the sampling points and combined the results into a single composite for each site.

To capture volatile organics, volatile organic analysis (VOA) vials were filled from the first liquid grab sample collected. All other

sludge and liquid samples were composited and thoroughly mixed and had any foreign material such as stones and other visible trash removed prior to sending them to the laboratory for analysis (USEPA 1987).

Produced water: To sample produced water, EPA took either grab samples from process lines or composited samples from tanks. Composite samples were taken at four evenly spaced depths between the liquid surface and the bottom of the tank, using only one sampling point per tank. Storage tanks that were inaccessible from the top had to be sampled from a tap at the tank bottom or at a flow line exiting the tank. For each site location, EPA combined individual samples into a single container to create the total liquid sample for that location. EPA mixed all composited produced water samples thoroughly and removed visible trash prior to transport to the laboratory (USEPA 1987).

Central treatment facilities: Both liquid and sludge samples were taken at central treatment facilities. All were composited grab samples using the same techniques described above for pits, tanks, or process lines (USEPA 1987).

API Sampling Methods

The API team divided pits into six sections and sampled in an "S" curve pattern in each section. There were 30 to 60 sample locations depending upon the size of the pit. API's sampling device was a metal or PVC pipe, which was driven into the pit solids. When the pipe could not be used, a stoppered jar attached to a ridged pole was used. Reserve pit supernatant was sampled using weighted bottles or bottom filling devices. Produced waters were usually sampled from process pipes or valves. API did not sample central treatment facilities (API 1987).

Analytical Methods

As for sampling methods, analytical methods used by EPA and by API were somewhat different. Each is briefly discussed below.

EPA Analytical Methods

EPA analyzed wastes for the RCRA characteristics in accordance with the Office of Solid Waste test methods manual (SW-846). In addition, since the Toxicity Characteristic Leaching Procedure (TCLP) has been proposed to be a RCRA test, EPA used that analytical procedure for certain wastes, as appropriate. EPA also used EPA methods 1624 and 1625, isotope dilution methods for organics, which have been determined to be scientifically valid for this application.

EPA's survey analyzed 444 organic compounds, 68 inorganics, 19 conventional contaminants, and 3 RCRA characteristics for a total of 534 analytes. Analyses performed included gas and liquid chromatography, atomic absorption spectrometry and mass spectrometry, ultraviolet detection method, inductively coupled plasma spectrometry, and dioxin and furan analysis. All analyses followed standard EPA methodologies and protocols and included full quality assurance/quality control (QA/QC) on certain tests (USEPA 1987).

Of these 534 analytes, 134 were detected in one or more samples. For about half of the sludge samples, extracts were taken using EPA's proposed Toxicity Characteristic Leaching Procedure (TCLP) and were analyzed for a subset of organics and metals. Samples from central pits and central treatment facilities were analyzed for 136 chlorinated dioxins and furans and 79 pesticides and herbicides (USEPA 1987).

API Analytical Methods

API analyzed for 125 organics, 29 metals, 15 conventional contaminants, and 2 RCRA characteristics for each sample. The same methods were used by API and EPA for analysis of metals and conventional

pollutants with some minor variations. For organics analysis EPA used methods 1624C and 1625C, while API used EPA methods 624 and 625. While the two method types are comparable, method 1624 (and 1625C) may give a more accurate result because of less interference from the matrix and a lower detection limit than methods 624 and 625. In addition, QA/QC on API's program has not been verified by EPA. See USEPA 1987 for a discussion of EPA analytical methods.

Results

Chemical Constituents Found by EPA in Oil and Gas Extraction Waste Streams

As previously stated, EPA collected a total of 101 samples from drilling sites, production sites, waste treatment facilities, and commercial waste storage and disposal facilities. Of these 101 samples, 42 were sludge samples and 59 were liquid samples (USEPA 1987).

Health-based numbers in milligrams per liter (mg/L) were tabulated for all constituents for which there are Agency-verified limits. These are either reference doses for noncarcinogens (Rfds) or risk-specific doses (RSDs) for carcinogens. RSDs were calculated, using the following risk levels: 10-6 for class A (human carcinogen) and 10-5 for class B (probable human carcinogen). Maximum contaminant limits (MCLs) were used, when available, then Rfds or RSDs. An MCL is an enforceable drinking water standard that is used by the Office of Solid Waste when ground water is a main exposure pathway.

Two multiples of the health-based limits (or MCLs) were calculated for comparison with the sample levels found in the wastes. Multiples of 100 were used to approximate the regulatory level set by the EP toxicity test (i.e., 100 x the drinking water standards for some metals and

pesticides). Multiples of 1,000 were used to approximate the concentration of a leachate which, as a first screen, is a threshold level of potential regulatory concern. Comparison of constituent levels found by direct analysis of waste with multiples of health-based numbers (or MCLs) can be used to approximate dispersion of this waste to surface waters. Comparison of constituent levels found by TCLP analysis of waste with multiples of health-based numbers (or MCLs) can be used to approximate dispersion of this waste to ground water.

For those polyaromatic hydrocarbons (PAHs) for which verified health-based numbers do not exist, limits were estimated by analogy with known toxicities of other PAHs. If structure activity analysis (SAR) indicated that the PAH had the potential to be carcinogenic, then it was assigned the same health-based number as benzo(a)pyrene, a potent carcinogen. If the SAR analysis yielded equivocal results, the PAH was assigned the limit given to indeno-(1,2,3-cd) pyrene, a PAH with possible carcinogenic potential. If the SAR indicated that the PAH was not likely to be carcinogenic, then it was assigned the same number as naphthalene, a noncarcinogen.

The analysis in this chapter does not account for the frequency of detection of constituents, or nonhuman health effects. Therefore, it provides a useful indication of the constituents deserving further study, but may not provide an accurate description of the constituents that have the potential to pose actual human health and environmental risks. Readers should refer to Chapter V, "Risk Modeling," for information on human health and environmental risks and should not draw any conclusions from the analysis presented in Chapter II about the level of risk posed by wastes from oil and gas wells.

EPA may further evaluate constituents that exceeded the health-based limit or MCL multiples to determine fate, transport, persistence, and toxicity in the environment. This evaluation may show that constituents

designated as secondary in the following discussion may not, in fact, be of concern to EPA.

Although the Toxicity Characteristics Leaching Procedure (TCLP) was performed on the sludge samples, the only constituent in the leach exhibiting concentrations that exceeded the multiples previously described was benzene in production tank bottom sludge. All of the other chemical constituents that exceeded the multiples were from direct analysis of the waste.

Constituents Present at Levels of Potential Concern

Because of the limited number of samples in relation to the large universe of facilities from which the samples were drawn, results of the waste sampling program conducted for this study must be analyzed carefully. EPA is conducting a statistical analysis of these samples.

Table II-4 shows EPA and API chemical constituents that were present in oil and gas extraction waste streams in amounts greater than health-based limits multiplied by 1,000 (primary concern) and those constituents that occurred within the range of multiples of 100 and 1,000 (secondary concern). Benzene and arsenic, constituents of primary and secondary concern respectively, by this definition, were modeled in the risk assessment chapter (Chapter V). The table compares waste stream location and sample phase with the constituents found at that location and phase. Table II-5 shows the number of samples compared with the number of detects in EPA samples for each constituent of potential concern.

The list of constituents of potential concern is not final. EPA is currently evaluating the data collected at the central treatment facilities and central pits, and more chemical constituents of potential concern may result from this evaluation. Also, statistical analysis of the sampling data is continuing.

Table II-4 Constituents of Concern Found In Waste Streams Sampled by EPA and API

	Production			Central treatment			Central pit	Drilling		
	Midpoint	Tank bottom	Endpoint	Influent	Tank	Effluent	Central pit	Drilling mud	Tank bottoms	Pit
Chemical Constituents **Primary concern**										
Benzene	L#	S# S+	L L#•		S#	L S	S#		S#	S S•
Phenanthrene		S #	L L#•		S#		S #	S	S #	
Lead				S#		S#	S#		L#	L# L• S# S#•
Barium			L	S#	S#	S#	S#	S#	L	L# L#• S# S#•
Secondary concern										
Arsenic		S	L			S	S			S S•
Fluoride				S		S	S			L S
Antimony			L•							

Legend:
- L: Liquid sample > 100 x health-based number
- S: Sludge sample > 100 x health-based number
- #: Denotes > 1,000 x health-based number
- L,S: EPA samples
- L•,S•: API samples
- +: TCLP extraction
- — All values determined from direct samples except as denoted by "+"

Table II-5 EPA Samples Containing Constituents of Concern

	Production			Central treatment			Central pit	Drilling		
	Midpoint	Tank bottom	Endpoint	Influent	Tank	Effluent	Central pit	Drilling mud	Tank bottoms	Pit
Primary concern										
Benzene	L5 (3)	S1 (1) +	L21 (16)		S2 (1)	L3 (2) S3 (1)	S3 (1)		S1 (1)	S18 (7)
Phenanthrene		S1 (1)	L21 (5)		S2 (2)		S3 (1)	S2 (1)	S1 (1)	
Lead				S1 (1)		S3 (3)	S3 (3)		L1 (1)	L17 (17) S21 (21)
Barium			L24 (21)	S1 (1)	S2 (1)	S3 (3)	S3 (3)	S1 (1)	L1 (1)	L17 (17) S21 (21)
Secondary concern										
Arsenic		S1 (1)	L24 (9)			S3 (3)	S3 (1)			S21 (11)
Fluoride				S1 (1)		S3 (3)	S3 (3)			L17 (17) S20 (20)

Legend:
- L: Liquid sample
- S: Sludge sample
- # (#) Number of samples (number of detects)
- \+ TCLP extract and direct extracts

Comparison to Constituents of Potential Concern Identified in the Risk Analysis

This report's risk assessment selected the chemical constituents that are most likely to dominate the human health and environmental risks associated with drilling wastes and produced water endpoints. Through this screening process, EPA selected arsenic, benzene, sodium, cadmium, chromium VI, boron, chloride, and total mobile ions as the constituents to model for risk assessment.[6]

The chemicals selected for the risk assessment modeling differ from the constituents of potential concern identified in this chapter's analysis for at least three reasons. First, the risk assessment screening accounted for constituent mobility by examining several factors in addition to solubility that affect mobility (e.g., soil/water partition coefficients) whereas, in Chapter II, constituents of potential concern were not selected on the basis of mobility in the environment. Second, certain constituents were selected for the risk assessment modeling based on their potential to cause adverse environmental effects as opposed to human health effects; the Chapter II analysis considers mostly human health effects. Third, frequency of detection was considered in selecting constituents for the risk analysis but was not considered in the Chapter II analysis.

Facility Analysis

Constituents of potential concern were chosen on the basis of exceedances in liquid samples or TCLP extract. Certain sludge samples are listed in Tables II-4 and II-5, since these samples, through direct

6 Mobile ions modeled in the risk assessment include chloride, sodium, potassium, calcium, magnesium, and sulfate.

chemical analysis, indicated the presence of constituents at levels exceeding the multiples previously described. One sludge sample analyzed by the TCLP method contained benzene in an amount above the level of potential concern. This sample is included in Tables II-4 and II-5. The sludge samples are shown for comparison with the liquid samples and TCLP extract and were not the basis for choice as a constituent of potential concern. Constituents found in the liquid samples or the TCLP extract in amounts greater than 100 times the health-based number are considered constituents of potential concern by EPA.

Central Treatment Facility

Benzene, the only constituent found in liquid samples at the central treatment facilities, was found in the effluent in amounts exceeding the level of potential concern.

Central Pit Facility

No constituent was found in the liquid phase in amounts exceeding the level of potential concern at central pit facilities.

Drilling Facilities

Lead and barium were found in amounts exceeding the level of potential concern in the liquid phase of the tank bottoms and the reserve pits that were sampled. Fluoride was found in amounts that exceeded 100 times the health-based number in reserve pit supernatant.

Production Facility

Benzene was present in amounts that exceeded the level of potential concern at the midpoint and the endpoint locations. Exceedances of the

level of potential concern that occurred only at the endpoint location were for phenanthrene, barium, arsenic, and antimony. Benzene was present in amounts exceeding the multiple of 1,000 in the TCLP leachate of one sample.

WASTE CHARACTERIZATION ISSUES

Toxicity Characteristic Leaching Procedure (TCLP)

The TCLP was designed to model a reasonable worst-case mismanagement scenario, that of co-disposal of industrial waste with municipal refuse or other types of biodegradable organic waste in a sanitary landfill. As a generic model of mismanagement, this scenario is appropriate for nonregulated wastes because those wastes may be sent to a municipal landfill. However, most waste from oil and gas exploration and production is not disposed of in a sanitary landfill, for which the test was designed. Therefore, the test may not reflect the true hazard of the waste when it is managed by other methods. However, if these wastes were to go to a sanitary landfill, EPA believes the TCLP would be an appropriate leach test to use.

For example, the TCLP as a tool for predicting the leachability of oily wastes placed in surface impoundments may actually overestimate that leachability. One reason for this overestimation involves the fact that the measurement of volatile compounds is conducted in a sealed system during extraction. Therefore, all volatile toxicants present in the waste are assumed to be available for leaching to ground water. None of the volatiles are assumed to be lost from the waste to the air. Since volatilization is a potentially significant, although as yet unquantified, route of loss from surface impoundments, the TCLP may overestimate the leaching potential of the waste. Another reason for overestimation is that the TCLP assumes that no degradation--either chemical, physical, or biological--will occur in the waste before the

leachate actually leaves the impoundment. Given that leaching is not likely to begin until a finite time after disposal and will continue to occur over many years, the assumption of no change may tend to overestimate leachability.

Conversely, the TCLP may underestimate the leaching potential of petroleum wastes. One reason for this assumption is a procedural problem in the filtration step of the TCLP. The amount of mobile liquid phase that is present in these wastes and that may migrate and result in ground-water contamination is actually underestimated by the TCLP. The TCLP requires the waste to be separated into its mobile and residue solid phases by filtration. Some production wastes contain materials that may clog the filter, indicating that the waste contains little or no mobile fraction. In an actual disposal environment, however, the liquid may migrate. Thus, the TCLP may underestimate the leaching potential of these materials. Another reason for underestimation may be that the acetate extraction fluid used is not as aggressive as real world leaching fluid since other solubilizing species (e.g., detergents, solvents, humic species, chelating agents) may be present in leaching fluids in actual disposal units. The use of a citric acid extraction media for more aggressive leaching has been suggested.

Because the TCLP is a generic test that does not take site-specific factors into account, it may overestimate waste leachability in some cases and underestimate waste leachability in other cases. This is believed to be the case for wastes from oil and gas exploration and production.

The EPA has several projects underway to investigate and quantify the leaching potential of oily matrices. These include using filter aids to prevent clogging of the filter, thus increasing filtration efficiency, and using column studies to quantitatively assess the degree to which oily materials move through the soil. These projects may result in a leach test more appropriate for oily waste.

Solubility and Mobility of Constituents

Barium is usually found in drilling waste as barium sulfate (barite), which is practically insoluble in water (Considine 1974). Barium sulfate may be reduced to barium sulfide, which is water soluble. It is the relative insolubility of barium sulfate that greatly decreases its toxicity to humans; the more soluble and mobile barium sulfide is also much more toxic (Sax 1984). Barium sulfide formation from barium sulfate requires a moist anoxic environment.

The organic constituents present in the liquid samples in concentrations of potential concern were benzene and phenanthrene. Benzene was found in produced waters and effluent from central treatment facilities, and phenanthrene was found in produced waters.

An important commingling effect that can increase the mobility of nonpolar organic solvents is the addition of small amounts of a more soluble organic solvent. This effect can significantly increase the extent to which normally insoluble materials are dissolved. This solubility enhancement is a log-linear effect. A linear increase in cosolvent concentration can lead to a logarithmic increase in solubility. This effect is also additive in terms of concentration. For instance, if a number of cosolvents exist in small concentrations, their total concentration may be enough to have a significant effect on nonpolar solvents with which the cosolvents come in contact (Nkedi-Kizza 1985, Woodburn et al. 1986). Common organic cosolvents are acetone, toluene, ethanol, and xylenes (Brown and Donnelly 1986).

Other factors that must be considered when evaluating the mobility of these inorganic and organic constituents in the environment are the use of surfactants at oil and gas drilling and production sites and the

general corrosivity of produced waters. Surfactants can enhance the solubility of many constituents in these waters. Produced waters have been shown to corrode casing (see damage cases in Chapter IV).

Changes in pH in the environment of disposal can cause precipitation of compounds or elements in waste and this can decrease mobility in the environment. Also adsorption of waste components to soil particles will attenuate mobility. This is especially true of soils containing clay because of the greater surface area of clay-sized particles.

Phototoxic Effect of Polycyclic Aromatic Hydrocarbons (PAH)

New studies by Kagan et al. (1984), Allred and Giesy (1985), and Bowling et al. (1983) have shown that very low concentrations (ppb in some cases) of polycyclic aromatic hydrocarbon (PAH) are lethal to some forms of aquatic wildlife when they are introduced to sunlight after exposure to the PAHs. This is called the phototoxic effect.

In the study conducted by Allred and Giesy (1985), it was shown that anthracene toxicity to Daphnia pulex resulted from activation by solar radiation of material present on or within the animals and not in the water. It appeared that activation resulted from anthracene molecules and not anthracene degeneration products. Additionally, it was shown that wavelengths in the UV-A region (315 to 380 nm) are primarily responsible for photo-induced anthracene toxicity.

It has been shown that PAHs are a typical component of some produced waters (Davani et al., 1986a). The practice of disposal of produced waters in unlined percolation pits is allowing PAHs and other constituents to migrate into and accumulate in soils (Eiceman et al., 1986a, 1986b).

pH and Other RCRA Characteristics

Of the RCRA parameters reactivity, ignitability, and corrosivity, no waste sample failed the first two. Reactivity was low and ignitability averaged 200^{o}F for all waste tested. On the average, corrosivity parameters were not exceeded, but one extreme did fail this RCRA test (See Table II-6). A solid waste is considered hazardous under RCRA if its aqueous phase has a pH less than or equal to 2 or greater than or equal to 12.5. As previously stated, a sludge sample is defined by EPA in this document as a sample containing a significant quantity of solids (normally greater than 1 percent).

Of the major waste types at oil and gas facilities, waste drilling muds and produced waters have an average neutral pH. Waste drilling fluid samples ranged from neutral values to very basic values, and produced waters ranged from neutral to acidic values. In most cases the sludge phase tends to be more basic than the liquid phases. An exception is the tank bottom waste at central treatment facilities, which has an average acidic value. Drilling waste tends to be basic in the liquid and sludge phases and failed the RCRA test for alkalinity in one extreme case. At production facilities the pH becomes more acidic from the midpoint location to the endpoint. This is probably due to the removal of hydrocarbons. This neutralizing effect of hydrocarbons is also shown by the neutral pH values of the production tank bottom waste. An interesting anomaly of Table II-6 is the alkaline values of the influent and effluent of central treatment facilities compared to the acidic values of the tank bottoms at these facilities. Because central treatment facilities accept waste drilling fluids and produced waters, acidic constituents of produced waters may be accumulating in tank bottom sludges. The relative acidity of the produced waters is also indicated by casing failures, as shown by some of the damage cases in Chapter IV.

Table II-6 pH Values for Exploration, Development and Production Wastes (EPA Samples)

	Midpoint	Tank bottom	Endpoint	Influent	Tank	Effluent	Central pit	Tank bottoms	Pit
Production									
Sludge		7.0; 7.0; 7.0							
Liquid	6.4; 6.6; 8.0		2.7; 7.6; 8.1						
Central treatment									
Sludge				8.8; 8.8; 8.8	2.0; 3.9; 5.8	6.7; 8.2; 10.0			
Liquid				5.7; 6.5; 7.3		7.0; 8.2; 10.1			
Central pit									
Sludge							7.2; 8.0; 9.2		
Liquid							5.7; 7.5; 8.5		
Drilling									
Sludge									6.8; 9.0; 12.8
Liquid								7.1; 7.1; 7.1	6.5; 7.7; 12.7

Legend:

#; #; # - minimum; average; maximum

Use of Constituents of Concern

The screening analysis conducted for the risk assessment identified arsenic, benzene, sodium, cadmium, chromium VI, boron, and chloride as the constituents that likely pose the greatest human health and environmental risks. The risk assessment's findings differ from this chapter's findings since this chapter's analysis did not consider the frequency of detection of constituents, mobility factors, or nonhuman health effects (see Table II-7). Some constituents found in Table II-4 were in waste streams causing damages as documented in Chapter IV.

Table II-7 Comparison of Potential Constituents of Concern That Were Modeled in Chapter V

Chemical	Chapter II*	Chapter V**	Reasons for not including in Chapter V risk analysis ***
Benzene	P	Yes	N/A
Phenanthrene	P	No	Low frequency in drilling pit and produced water samples; low ground-water mobility; relatively low concentration-to-toxicity ratio; unverified reference dose used for Chapter 2 analysis.
Lead	P	No	Low ground-water mobility.
Barium	P	No	Low ground-water mobility.
Arsenic	S	Yes	N/A
Fluoride	S	No	Relatively low concentration-to-toxicity ratio.
Antimony	S	No	Low frequency in drilling pit and produced water samples.

* P = primary concern in Chapter II; S = secondary concern in Chapter II.

** Yes = modeled in Chapter V analysis; no = not modeled in Chapter V analysis.

*** Table summarizes primary reasons only; additional secondary reasons may also exist.

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CHAPTER III

CURRENT AND ALTERNATIVE WASTE MANAGEMENT PRACTICES

INTRODUCTION

Managing wastes produced by the oil and gas industry is a large task. By the estimates gathered for this report, in 1985 over 361 million barrels of drilling muds and 20.9 billion barrels of produced water were disposed of in the 33 States that have significant exploration, development, and production activity. In that same year, there were 834,831 active oil and gas wells, of which about 70 percent (580,000 wells) were stripper operations.

The focus of this section is to review current waste management technologies employed for wastes at all phases of the exploration-development-production cycle of the onshore oil and gas industry. It is convenient to divide wastes into two broad categories. The first category includes drilling muds, wellbore cuttings, and chemical additives related to the drilling and well completion process. These wastes tend to be managed together and may be in the form of liquids, sludges, or solids. The second broad category includes all wastes associated with oil and gas production. Produced water is the major waste stream and is by far the highest volume waste associated with oil and gas production. Other production-related wastes include relatively small volumes of residual bactericides, fungicides, corrosion inhibitors, and other additives used to ensure efficient production; wastes from oil/gas/water separators and other onsite processing facilities; production tank bottoms; and scrubber bottoms.[1]

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[1] For the purpose of this chapter, all waste streams, whether exempt or nonexempt, are discussed.

In addition to looking at these two general waste categories, it is also important to view waste management in relation to the sequence of operations that occurs in the life cycle of a typical well. The chronology involves both drilling and production--the two phases mentioned above--but it also can include "post-closure" events, such as seepage of native brines into fresh ground water from improperly plugged or unplugged abandoned wells or leaching of wastes from closed reserve pits.

Section 8002(m) of RCRA requires EPA to consider both current and alternative technologies in carrying out the present study. Sharp distinctions between current and alternative technologies are difficult to make because of the wide variation in practices among States and among different types of operations. Furthermore, waste management technology in this field is fairly simple. At least for the major high-volume streams, there are no significant newly invented, field-proven technologies in the research or development stage that can be considered "innovative" or "emerging." Although practices that are routine in one location may be considered innovative or alternative elsewhere, virtually every waste management practice that exists can be considered "current" in one specific situation or another. This is because different climatological or geological settings may demand different management procedures, either for technical convenience in designing and running a facility or because environmental settings in a particular region may be unique. Depth to ground water, soil permeability, net evapotranspiration, and other site-specific factors can strongly influence the selection and design of waste management practices. Even where geographic and production variables are similar, States may impose quite different requirements on waste management, including different permitting conditions.

Long-term improvements in waste management need not rely, however, purely on increasing the use of better existing technology. The Agency does foresee the possibility of significant technical improvements in future technologies and practices. Examples include incineration and other thermal treatment processes for drilling fluids; conservation, recycling, reuse, and other waste minimization techniques; and wet air oxidation and other proven technologies that have not yet been applied to oil and gas operations.

Sources of Information

The descriptions and interpretations presented here are based on State or Federal regulatory requirements, published technical information, observations gathered onsite during the waste sampling program, and interviews with State officials and private industry. Emphasis is placed on practices in 13 States that represent a cross-section of the petroleum extraction industry based on their current drilling activity, rank in production, and geographic distribution. (See Table III-1.)

Limitations

Data on the prevalence, environmental effectiveness, and enforcement of waste management requirements currently in effect in the petroleum-producing States are difficult to obtain. Published data are scarce and often outdated. Some of the State regulatory agencies that were interviewed for this study have only very limited statistical information on the volumes of wastes generated and on the relative use of the various methods of waste disposal within their jurisdiction. Time was not available to gather statistics from other States that have significant oil and gas activity. This lack of concrete data makes it difficult for EPA to complete a definitive assessment of available disposal options. EPA is collecting additional data on these topics.

Table III-1 States with Major Oil Production Used as Primary References in This Study

Alaska
Arkansas
California
Colorado
Kansas
Louisiana
Michigan
New Mexico
Ohio
Oklahoma
Texas
West Virginia
Wyoming

DRILLING-RELATED WASTES

Description of Waste

Drilling wastes include a wide variety of materials, ranging in volume from the thousands of barrels of fluids ("muds") used to drill a well, to the hundreds of barrels of drill cuttings extracted from the borehole, to much smaller quantities of wastes associated with various additives and chemicals sometimes used to condition drilling fluids. A general description of each of these materials is presented in broad terms below.

Drilling Fluids (Muds)

The largest volume drilling-related wastes generated are the spent drilling fluids or muds. The composition of modern drilling fluids or muds can be quite complex and can vary widely, not only from one geographical area to another but also from one depth to another in a particular well as it is drilled.

Muds fall into two general categories: water-based muds, which can be made with fresh or saline water and are used for most types of drilling, and oil-based muds, which can be used when water-sensitive formations are drilled, when high temperatures are encountered, or when it is necessary to protect against severe drill string corrosion in hostile downhole environments. Drilling muds contain four essential parts: (1) liquids, either water or oil; (2) reactive solids, the viscosity- and density-building part of the system, often bentonite clays; (3) inert solids such as barite; and (4) additives to control the chemical, physical, and biological properties of the mud. These basic components perform various functions. For example, clays increase viscosity and

density, barium sulfate (barite) acts as a weighting agent to maintain pressure in the well, and lime and caustic soda increase pH and control viscosity. Additional conditioning materials include polymers, starches, lignitic material, and various other chemicals (Canter et al. 1984).

Table III-2 presents a partial list, by use category, of additives to drilling muds (Note: this table is based on data that may, in some cases, be outdated.)

Cuttings

Well cuttings include all solid materials produced from the geologic formations encountered during the drilling process that must be managed as part of the content of the waste drilling mud. Drill cuttings consist of rock fragments and other heavy materials that settle out by gravity in the reserve pit. Other materials, such as sodium chloride, are soluble in fresh water and can pose problems in waste disposal. Naturally occurring arsenic may also be encountered in significant concentrations in certain wells and in certain parts of the country and must be disposed of appropriately. (Written communication with Mr. Don Basko, Wyoming Oil and Gas Conservation Commission.)

Waste Chemicals

In the course of drilling operations, chemicals may be disposed of by placing them in the well's reserve pit. These can include any substances deliberately added to the drilling mud for the various purposes mentioned above (see Table III-2).

Table III-2 Characterization of Oil and Gas Drilling Fluids

Source: Information in this table was taken from American Petroleum Institute (API) Bulletin 13F (1978). Drilling practices have evolved significantly in some respects since its publication; the information presented below may therefore not be fully accurate or current.

Bases

Bases used in formulating drilling fluid are predominantly fresh water, with minor use of saltwater or oils, including diesel and mineral oils. It is estimated that the industry used 30,000 tons of diesel oil per year in drilling fluid in 1978.[a]

Weighting Agents

Common weighting agents found in drilling fluids are barite, calcium carbonate, and galena (PbS).[b] Approximately 1,900,000 tons of barite, 2,500 tons of calcium carbonate, and 50 tons of galena (the mineral form of lead) are used in drilling each year.

Viscosifiers

Viscosifiers found in drilling fluid include:

• Bentonite clays	650,000 tons/year
• Attapulgite/sepiolite	85,000 tons/year
• Asphalt/gilsonite	10,000 tons/year
• Asbestos	10,000 tons/year
• Bio-polymers	500 tons/year

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[a] This figure included contributions from offshore operations. According to API, use of diesel oil in drilling fluid has been substantially reduced in the past 10 years principally as a result of its restricted use in offshore operations.

[b] API states that galena is no longer used in drilling mud.

Table III-2 (continued)

Dispersants

Dispersants used in drilling fluid include:

• Cadmium, chromium, iron, and other metal lignosulfonates	65,000 tons/year
• Natural, causticized chromium and zinc lignite	50,000 tons/year
• Inorganic phosphates	1,500 tons/year
• Modified tannins	1,200 tons/year

Fluid Loss Reducers

Fluid loss reducers used in drilling fluid include:

• Starch/organic polymers	15,000 tons/year
• Cellulosic polymers (CMC, HEC)	12,500 tons/year
• Guar gum	100 tons/year
• Acrylic polymers	2,500 tons/year

Lost Circulation Materials

Lost circulation materials used comprise a variety of nontoxic substances including cellophane, cotton seed, rice hulls, ground Formica, ground leather, ground paper, ground pecan and walnut shells, mica, and wood and cane fibers. A total of 20,000 tons of these materials is used per year.

Table III-2 (continued)

Surface Active Agents

Surface active agents (used as emulsifiers, detergents, defoamants) include:

• Fatty acids, naphthenic acids, and soaps	5,000 tons/year
• Organic sulfates/sulfonates	1,000 tons/year
• Aluminum stearate	(quantity not available)

Lubricants

Lubricants used include:

• Vegetable oils	500 tons/year
• Graphite	<5 tons/year

Flocculating Agents

The primary flocculating agents used in drilling are:

• Acrylic polymers	2,500 tons/year

Biocides

Biocides used in drilling include:

• Organic amines, amides, amine salts	1,000 tons/year
• Aldehydes (paraformaldehyde)	500 tons/year
• Chlorinated phenols	<1 ton/year
• Organosulfur compounds and organometallics	(quantity not available)

Miscellaneous

Miscellaneous drilling fluid additives include:

• Ethoxylated alkyl phenols	1,800 tons/year
• Aaliphatic alcohols	<10 tons/year
• Aluminum anhydride derivatives and chrom alum	(quantities not available)

Table III-2 (continued)

Commercial Chemicals

Commercial chemicals used in drilling fluid include:

• Sodium hydroxide	50,000 tons/year
• Sodium chloride	50,000 tons/year
• Sodium carbonate	20,000 tons/year
• Calcium chloride	12,500 tons/year
• Calcium hydroxide/calcium oxide	10,000 tons/year
• Potassium chloride	5000 tons/year
• Sodium chromate/dichromate[a]	4,000 tons/year
• Calcium sulfate	500 tons/year
• Potassium hydroxide	500 tons/year
• Sodium bicarbonate	500 tons/year
• Sodium sulfite	50 tons/year
• Magnesium oxide	<10 tons/year
• Barium carbonate	(quantity not available)

These commercial chemicals are used for a variety of purposes including pH control, corrosion inhibition, increasing fluid phase density, treating out calcium sulfate in low pH muds, treating out calcium sulfate in high pH muds.

Corrosion Inhibitors

Corrosion inhibitors used include:

• Iron oxide	100 tons/year
• Ammonium bisulfite	100 tons/year
• Basic zinc carbonate	100 tons/year
• Zinc chromate	<10 tons/year

[a] API states that sodium chromate is no longer used in drilling mud.

Fracturing and Acidizing Fluids

Fracturing and acidizing are processes commonly used to enlarge existing channels and open new ones to a wellbore for several purposes:

- To increase permeability of the production formation of a well;
- To increase the zone of influence of injected fluids used in enhanced recovery operations; and
- To increase the rate of injection of produced water and industrial waste material into disposal wells.

The process of "fracturing" involves breaking down the formation, often through the application of hydraulic pressure, followed by pumping mixtures of gelled carrying fluid and sand into the induced fractures to hold open the fissures in the rocks after the hydraulic pressure is released. Fracturing fluids can be oil-based or water-based. Additives are used to reduce the leak-off rate, to increase the amount of propping agent carried by the fluid, and to reduce pumping friction. Such additives may include corrosion inhibitors, surfactants, sequestering agents, and suspending agents. The volume of fracturing fluids used to stimulate a well can be significant.[2] Closed systems, which do not involve reserve pits, are used very occasionally (see discussion below). However, closed systems are widely used in California. Many oil and gas fields currently being developed contain low-permeability reservoirs that may require hydraulic fracturing for commercial production of oil or gas.

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2 Mobile Oil Co. recently set a well stimulation record (single stage) in a Wilcox formation well in Zapata County, Texas, by placing 6.3 million pounds of sand, using a fracturing fluid volume of 1.54 million gallons (World Oil, January 1987).

The process of "acidizing" is done by injecting acid into the target formation. The acid dissolves the rock, creating new channels to the wellbore and enhancing existing ones. The two basic types of acidizing treatments used are:

- Low-pressure acidizing: acidizing that avoids fracturing the formation and allows acid to work through the natural pores (matrix) of the formation.
- Acid fracturing: acidizing that utilizes high pressure and high volumes of fluids (acids) to fracture rock and to dissolve the matrix in the target formation.

The types of acids normally used include hydrochloric acid (in concentrations ranging from 15 to 28 percent in water), hydrochloric-hydrofluoric acid mixtures (12 percent and 3 percent, respectively), and acetic acid. Factors influencing the selection of acid type include formation solubility, reaction time, reaction products effects, and the sludging and emulsion-forming properties of the crude oil. The products of spent acid are primarily carbon dioxide and water.

Spent fracturing and acidizing fluid may be discharged to a tank, to the reserve pit, or to a workover pit.

<u>Completion and Workover Fluids</u>

Completion and workover fluids are the fluids placed in the wellbore during completion or workover to control the flow of native formation fluids, such as water, oil, or gas. The base for these fluids is usually water. Various additives are used to control density, viscosity, and filtration rates; prevent gelling of the fluid; and reduce corrosion. They include a variety of salts, organic polymers, and corrosion inhibitors.

When the completion or workover operation is completed, the fluids in the wellbore are discharged into a tank, the reserve pit, or a workover pit.

Rigwash and Other Miscellaneous Wastes

Rigwash materials are compounds used to clean decks and other rig equipment. They are mostly detergents but can include some organic solvents, such as degreasers.

Other miscellaneous wastes include pipe dope used to lubricate connections in pipes, sanitary sewage, trash, spilled diesel oil, and lubricating oil.

All of these materials may, in many operations, be disposed of in the reserve pit.

ONSITE DRILLING WASTE MANAGEMENT METHODS

Several waste management methods can be used to manage oil and gas drilling wastes onsite. The material presented below provides a separate discussion for reserve pits, landspreading, annular disposal, solidification of reserve pit wastes, treatment and disposal of liquid wastes to surface water, and closed treatment systems.

Several waste management methods may be employed at a particular site simultaneously. Issues associated with reserve pits are particularly complex because reserve pits are both an essential element of the drilling process <u>and</u> a method for accumulating, storing, and disposing of wastes. This section therefore begins with a general discussion of

several aspects of reserve pits--design, construction, operation, and closure--and then continues with more specific discussions of the other technologies used to manage drilling wastes.

Reserve Pits

Description

Reserve pits, an essential design component in the great majority of well drilling operations,[3] are used to accumulate, store, and, to a large extent, dispose of spent drilling fluids, cuttings, and associated drill site wastes generated during drilling, completion, and testing operations.

There is generally one reserve pit per well. In 1985, an estimated 70,000 reserve pits were constructed. In the past, reserve pits were used both to remove and dispose of drilled solids and cuttings and to store the active mud system prior to its being recycled to the well being drilled. As more advanced solids control and drilling fluid technology has become available, mud tanks have begun to replace the reserve pit as the storage and processing area for the active mud system, with the reserve pit being used to dispose of waste mud and cuttings. Reserve pits will, however, continue to be the principal method of drilling fluid storage and management.

A reserve pit is typically excavated directly adjacent to the site of the rig and associated drilling equipment. Pits should be excavated from undisturbed, stable subsoil so as to avoid pit wall failure. Where it is impossible to excavate below ground level, the pit berm (wall) is usually constructed as an earthen dam that prevents runoff of liquid into adjacent areas.

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[3] Closed systems, which do not involve reserve pits, are used very occasionally (see discussion below). However, closed systems are widely used in California.

In addition to the components found in drilling mud, common constituents found in reserve pits include salts, oil and grease, and dissolved and/or suspended heavy metals. Sources of soluble salt contamination include formation waters, downhole salt layers, and drilling fluid additives. Sources of organic contamination include lubricating oil from equipment leaks, well pressure control equipment testing, heavy oil-based lubricants used to free stuck drill pipe, and, in some cases, oil-based muds used to drill and complete the target formation.[4] Sources of potential heavy metal contamination include drilling fluid additives, drilled solids, weighting materials, pipe dope, and spilled chemicals (Rafferty 1985).

The reserve pit itself can be used for final disposal of all or part of the drilling wastes, with or without prior onsite treatment of wastes, or for temporary storage prior to offsite disposal. Reserve pits are most often used in combination with some other disposal techniques, the selection of which depends on waste type, geographical location of the site, climate, regulatory requirements, and (if appropriate) lease agreements with the landowner.

The major onsite waste disposal methods include:

- Evaporation of supernatant;
- Backfilling of the pit itself, burying the pit solids and drilled cuttings by using the pit walls as a source of material (the most common technique);
- Landspreading all or part of the pit contents onto the area immediately adjacent to the pit;

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4 Charles A. Koch of the North Dakota Industrial Commission, Oil and Gas Division, states that "A company would not normally change the entire drilling fluid for just the target zone. This change would add drastically to the cost of drilling."

- Onsite treatment and discharge;
- Injecting or pumping all or part of the wastes into the well annulus; and
- Discharge to surface waters.

Another less common onsite management method is chemical solidification of the wastes.

Dewatering and burial of reserve pit contents (or, alternatively, landspreading the pit contents) are discussed here because they are usually an integral aspect of the design and operation of a reserve pit. The other techniques are discussed separately.

Dewatering of reserve pit wastes is usually accomplished through natural evaporation or skimming of pit liquids. Evaporation is used where climate permits. The benefits of evaporation may be overstated. In the arid climate of Utah, 93 percent of produced waters in an unlined pit percolated into the surrounding soil. Only 7 percent of the produced water evaporated (Davani et al. 1985). Alternatively, dewatering can be accomplished in areas of net precipitation by siphoning or pumping off free liquids. This is followed by disposal of the liquids by subsurface injection or by trucking them offsite to a disposal facility. Backfilling consists of burying the residual pit contents by pushing in the berms or pit walls, followed by compaction and leveling. Landspreading can involve spreading the excess muds that are squeezed out during the burial operation on surrounding soils; where waste quantities are large, landowners' permission is generally sought to disperse this material on land adjacent to the site. (This operation is different from commercial landfarming, which is discussed later.)

Environmental Performance

Construction of reserve pits is technically simple and straightforward. They do not require intensive maintenance to ensure proper function, but they may, in certain circumstances, pose environmental hazards during their operational phase.

Pits are generally built or excavated into the surface soil zones or into unconsolidated sediments, both of which are commonly highly permeable. The pits are generally unlined,[5] and, as a result, seepage of liquid and dissolved solids may occur through the pit sides and bottom into any shallow, unconfined freshwater aquifers that may be present. When pits are lined, materials used include plastic liners, compacted soil, or clay. Because reserve pits are used for temporary storage of drilling mud, any seepage of pit contents to ground water may be temporary, but it can in some cases be significant, continuing for decades (USEPA 1986).

Other routes of environmental exposure associated with reserve pits include rupture of pit berms and overflow of pit contents, with consequent discharge to land or surface water. This can happen in areas of high rainfall or where soil used for berm construction is particularly unconsolidated. In such situations, berms can become saturated and weakened, increasing the potential for failure. Leaching of pollutants after pit closure can also occur and may be a long-term problem especially in areas with highly permeable soils.

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5 An API study suggests that 37 percent of reserve pits are lined with a clay or synthetic liner.

Annular Disposal of Pumpable Drilling Wastes

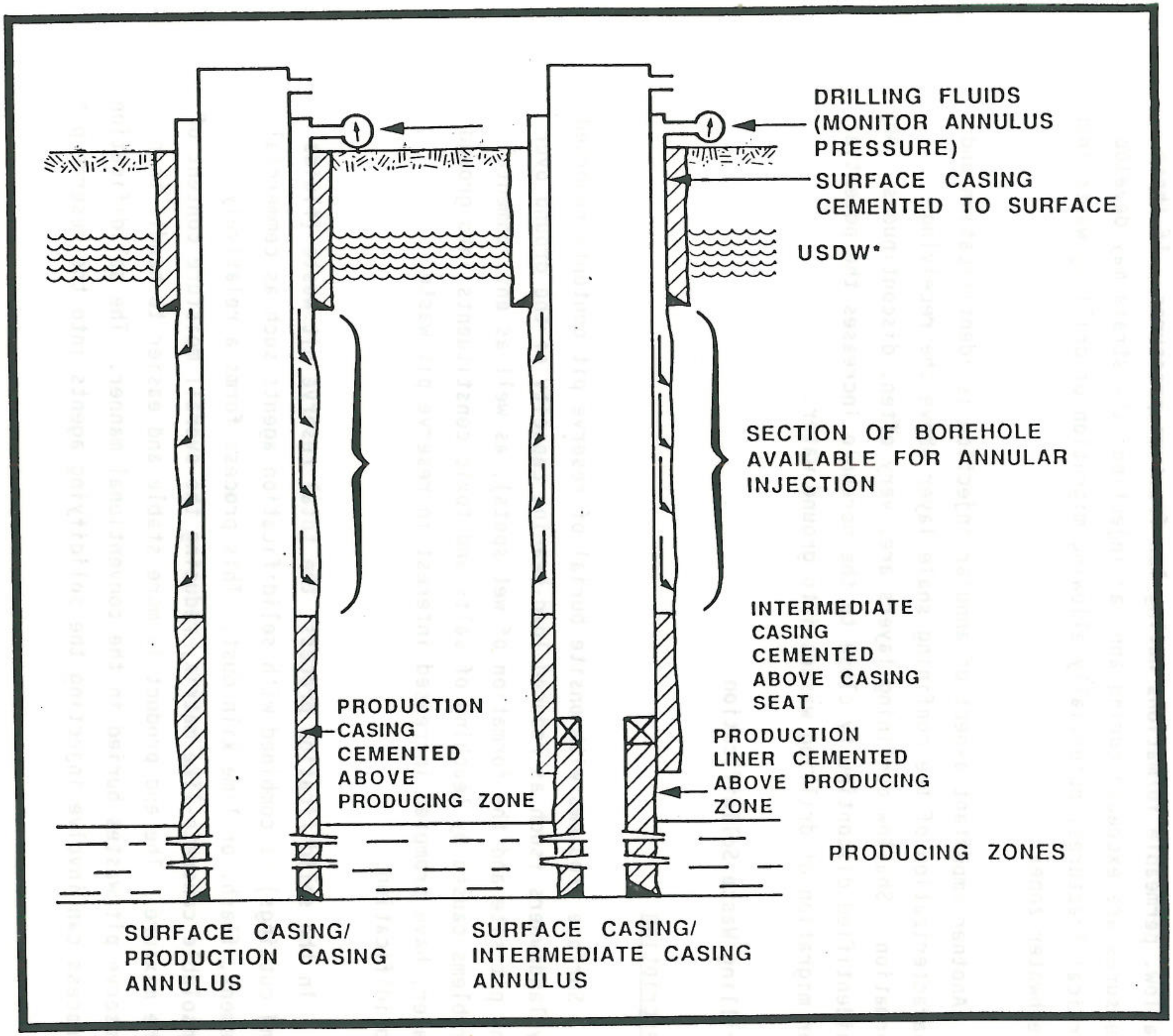
Description

Annular disposal involves the pumping of waste drilling fluids down the annulus created between the surface and intermediate casing of a well (see Figure III-1). (Disposal of solids is accomplished by using burial, solidification, landfarming, or landspreading techniques.) Disposal down the surface casing in the absence of an intermediate casing is also considered annular disposal. Annular disposal of pumpable drilling wastes is significantly more costly than evaporation, dewatering, or land application and is generally used when the waste drilling fluid contains an objectionable level of a contaminant or contaminants (such as chlorides, metals, oil and grease, or acid) which, in turn, limits availability of conventional dewatering or land application of drilling wastes. However, for disposal in a "dry" hole, costs may be relatively low. No statistics are available on how frequently annular injection of drilling wastes is used.

Environmental Performance

The well's surface casing is intended to protect fresh ground-water zones during drilling and after annular injection. To avoid adverse impacts on ground water in the vicinity of the well after annular injection, it is important that surface casing be sound and properly cemented in place. There is no feasible way to test the surface casing for integrity without incurring significant expense.

Assuming the annulus is open and the surface casing has integrity, the critical implementation factor is the pressure at which the reserve



* UNDERGROUND SOURCE OF DRINKING WATER
NOTE: NOT TO SCALE

Figure III-1 Annular Disposal of Waste Drilling Fluids

pit contents are injected. The receiving strata are usually relatively shallow, permeable formations having low fracture pressures. If these pressures are exceeded during annular injection, the strata may develop vertical fractures, potentially allowing migration of drilling waste into freshwater zones.

Another important aspect of annular injection is identification and characterization of the confining shale layer above the receiving formation. Shallow confining layers are, very often, discontinuous. Any unidentified discontinuity close to the borehole increases the potential for migration of drilling wastes into ground water.

Drilling Waste Solidification

Description

Surface problems with onsite burial of reserve pit contents reported by landowners (such as reduced load-bearing capacity of the ground over the pit site and the formation of wet spots), as well as environmental problems caused by leaching of salts and toxic constituents into ground water, have prompted increased interest in reserve pit waste solidification.

In the solidification process, the total reserve pit waste (fluids and cuttings) is combined with solidification agents such as commercial cement, flash, or lime kiln dust. This process forms a relatively insoluble concrete-like matrix, reducing the overall moisture content of the mixture. The end product is more stable and easier to handle than reserve pit wastes buried in the conventional manner.. The solidification process can involve injecting the solidifying agents into the reserve pit

or pumping the wastes into a mixing chamber near the pit. The waste does not have to be dewatered prior to treatment. Solidification can increase the weight and bulk of the treated waste, which may in some cases be a disadvantage of this method.

Environmental Performance

Solidification of reserve pit wastes offers a variety of environmental improvements over simple burial of wastes, with or without dewatering. By reducing the mobility of potentially hazardous materials, such as heavy metals, the process decreases the potential for contamination of ground water from leachate of unsolidified, buried reserve pit wastes. Bottom sludges, in which heavy metals largely accumulate, may continue to leach into ground water. (There are no data to establish whether the use of kiln dust would add harmful constituents to reserve pit waste. Addition of kiln dust would increase the volume of waste to be managed.)

Treatment and Discharge of Liquid Wastes to Land or Surface Water

Description

Discharge of waste drilling fluid to surface water is prohibited by EPA's zero discharge effluent guideline. However, in the Gulf Coast area, the liquid phase of waste drilling muds having low chloride concentrations is chemically treated for discharge to surface water. The treated aqueous phase (at an appropriate alkaline pH) can then be

discharged to land or surface water bodies.[6] The addition of selected reagents to reserve pit liquids must achieve the necessary reactions to allow effective separation of the suspended solids prior to dewatering of the sludge in the reserve pit.

Onsite treatment methods used prior to discharge are commercially available for reserve pit fluids as well as for solids. They are typically provided by mobile equipment brought to the drill site. These methods include pH adjustment, aeration, coagulation and flocculation, centrifugation, filtration, dissolved gas flotation, and reverse osmosis. All these methods, however, are more expensive than the more common approach of dewatering through evaporation and percolation. Usually, a treatment company employs a combination of these methods to treat the sludge and aqueous phases of reserve pit wastes.

Environmental Performance

Treatment and discharge of liquid wastes are used primarily to shorten the time necessary to close a pit.

Closed Cycle Systems

Description

A closed cycle waste treatment system can be an alternative to the use of a reserve pit for onsite management and disposal of drilling

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6 David Flannery states that his interpretation of EPA's effluent guidelines would preclude such a discharge. "On July 4, 1987, a petition was filed with EPA to revise the effluent guideline. If that petition is granted, stream discharges of drilling fluid and produced fluids would be allowed at least from operations in the Appalachian States."

wastes. Essentially an adaptation of offshore systems for onshore use, closed systems have come into use relatively recently. Because of their high cost, they are used very rarely, usually only when operations are located at extremely delicate sites (such as a highly sensitive wildlife area), in special development areas (such as in the center of an urbanized area), or where the cost of land reclamation is considered excessive. They can also be used where limited availability of makeup water for drilling fluid makes control of drill cuttings by dilution infeasible.

Closed cycle systems are defined as systems in which mechanical solids control equipment (shakers, impact type sediment separation, mud cleaners, centrifuges, etc.) and collection equipment (roll-off boxes, vacuum trucks, barges, etc.) are used to minimize waste mud and cutting volumes to be disposed of onsite or offsite. This in turn maximizes the volume of drilling fluid returned to the active mud system. Benefits derived from the use of this equipment include the following (Hanson et al. 1986):

- A reduction in the amount of water or oil needed for mud maintenance;
- An increased rate of drill bit penetration because of better solids control;
- Lower mud maintenance costs;
- Reduced waste volumes to be disposed of; and
- Reduction in reserve pit size or total elimination of the reserve pit.

Closed cycle systems range from very complex to fairly simple. The degree of solids control used is based on the mud type and/or drilling program and the economics of waste transportation to offsite disposal

facilities (particularly the dollars per barrel charges at these facilities versus the cost per day for additional solids control equipment rental). Closed systems at drill sites can be operated to have recirculation of the liquid phase, the solid phase, or both. In reality, there is no completely closed system for solids because drill cuttings are always produced and removed. The closed system for solids, or the mud recirculation system, can vary in design from site to site, but the system must have sufficient solids handling equipment to effectively remove the cuttings from muds to be reused.

Water removed from the mud and cuttings can be reused. It is possible to operate a separate closed system for water reuse onsite along with the mud recirculation system. As with mud recirculation systems, the design of a water recirculation system can vary from site to site, depending on the quality of water required for further use. This may include chemical treatment of the water.

Environmental Performance

Although closed systems offer many environmental advantages, their high cost seriously reduces their potential use, and the mud and cuttings must still ultimately be disposed of.

Disposal of Drilling Wastes on the North Slope of Alaska--A Special Case

The North Slope is an arctic desert consisting of a wet coastal plain underlain by up to 2,500 feet of permafrost, the upper foot or two of which thaws for about 2 months a year. The North Slope is considered to be a sensitive area because of the extremely short growing season of the tundra, the short food chain, and the lack of species diversity found in

this area. Because of the area's severe climate, field practices for management of drilling media and resulting waste are different on the North Slope of Alaska from those found elsewhere in the country. In the Arctic, production pads are constructed above ground using gravel. This type of construction prevents melting of the permafrost. Reserve pits are constructed on the production pads using gravel and native soils for the pit walls; they become a permanent part of the production facility. Pits are constructed above and below grade.

Because production-related reserve pits on the North Slope are permanent, the contents of these pits must be disposed of periodically. This is done by pumping the aqueous phase of a pit onto the tundra. This pumping can take place after a pit has remained inactive for 1 year to allow for settling of solids and freeze-concentration of constituents; the aqueous phase is tested for effluent limits for various constituents established by the State of Alaska. The National Pollutant Discharge Elimination System (NPDES) permit system does not cover these discharges. An alternative to pumping of the reserve pit liquids onto the tundra is to "road-spread" the liquid, using it as a dust control agent on the gravel roads connecting the production facilities. Prior to promulgation of new State regulations, no standards other than "no oil sheen" were established for water used for dust control. ADEC now requires that at the edge of the roads, any leachate, runoff, or dust must not cause a violation of the State water quality standards. Alaska is evaluating the need for setting standards for the quality of fluids used to avoid undesirable impacts. Other North Slope disposal options for reserve pit liquids include disposal of the reserve pit liquids through annular injection or disposal in Class II wells. The majority of reserve pit liquids are disposed of through discharge to the tundra.

Reserve pits on the North Slope are closed by dewatering the pit and filling it with gravel. The solids are frozen in place above grade and

below grade. Freezing in place of solid waste is successful as long as hydrocarbon contamination of the pit contents is minimized. Hydrocarbon residue in the pit contents can prevent the solids from freezing completely. In above-grade structures thawing will occur in the brief summer. If the final waste surface is below the active thaw zone, the wastes will remain frozen year-round.

Disposal of produced waters on the North Slope is through subsurface injection. This practice does not vary significantly from subsurface injection of production wastes in the Lower 48 States, and a description of this practice can be found under "Production-Related Wastes" below.

Environmental Performance

Management of drilling media and associated waste can be problematic in the Arctic. Because of the severe climate, the reserve pits experience intense freeze-thaw cycles that can break down the stability of the pit walls, making them vulnerable to erosion. From time to time, reserve pits on the North Slope have breached, spilling untreated liquid and solid waste onto the surrounding tundra. Seepage of untreated reserve pit fluids through pit walls is also known to occur.

Controlled discharge of excess pit liquids is a State-approved practice on the North Slope; however, the long-term effects of discharging large quantities of liquid reserve pit waste on this sensitive environment are of concern to EPA, Alaska Department of Environmental Conservation (ADEC), and officials from other Federal agencies. The existing body of scientific evidence is insufficient to conclusively demonstrate whether or not there are impacts resulting from this practice.

OFFSITE WASTE MANAGEMENT METHODS

Offsite waste management methods include the use of centralized disposal pits (centralized injection facilities, either privately or commercially operated, will be discussed under "subsurface injection" of production wastes), centralized treatment facilities, commercial landfarming, and reconditioning and reuse of drilling media.

Centralized Disposal Pits

Description

Centralized disposal pits are used in many States to store and dispose of reserve pit wastes. In some cases, large companies developing an extensive oil or gas field may operate centralized pits within the field for better environmental control and cost considerations. Most centralized pits are operated commercially, primarily for the use of smaller operators who cannot afford to construct properly designed and sited disposal pits for their own use. They serve the disposal needs for drilling or production wastes from multiple wells over a large geographical area. Centralized pits are typically used when storage and disposal of pit wastes onsite are undesirable because of the high chloride content of the wastes or because of some other factor that raises potential problems for the operators.[7] Wastes are generally transported to centralized disposal pits in vacuum trucks. These centralized pits are usually located within 25 miles of the field sites they serve.

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[7] Operators, for instance, may be required under their lease agreements with landowners not to dispose of their pit wastes onsite because of the potential for ground-water contamination.

The number of commercial centralized pits in major oil-producing States may vary from a few dozen to a few hundred. The number of privately developed centralized pits is not known.

Technically, a centralized pit is identical in basic construction to a conventional reserve pit. It is an earthen impoundment, which can be lined or unlined and used to accumulate, store, and dispose of drilling fluids from drilling operations within a certain geographical area. Centralized pits tend to be considerably larger than single-well pits; surface areas can be as large as 15 acres, with depths as great as 50 feet. Usually no treatment of the pit contents is performed. Some centralized pits are used as separation pits, allowing for solids settling. The liquid recovered from this settling process may then be injected into disposal wells. Many centralized pits also have State requirements for oil skimming and reclamation.

<u>Environmental Performance</u>

Centralized pits are a storage and disposal operation; they usually perform no treatment of wastes.

Closure of centralized pits may pose adverse environmental impacts. In the past some pits have been abandoned without proper closure, sometimes because of the bankruptcy of the original operator. So far as EPA has been able to determine, only one State, Louisiana, has taken steps to avoid this eventuality; Louisiana requires operators to post a bond or irrevocable letter of credit (based on closing costs estimated in the facility plan) and have at least $1 million of liability insurance to cover operations of open pits.

Centralized Treatment Facilities

Description

A centralized treatment facility for oil and gas drilling wastes is a process facility that accepts such wastes solely for the purpose of conditioning and treating wastes to allow for discharge or final disposal. Such facilities are distinct from centralized disposal pits, which do not treat drilling wastes as part of their storage and disposal functions. The use of such facilities may remove the burden of disposal of wastes from the operators in situations where State regulations have imposed stringent disposal requirements for burying reserve pit wastes onsite.

Centralized treatment may be an economically viable alternative to onsite waste disposal for special drilling fluids, such as oil-based muds, which cannot be disposed of in a more conventional manner. The removal, hauling, and treatment costs incurred by treatment at commercial sites will generally outweigh landspreading or onsite burial costs. A treatment facility can have a design capacity large enough to accept a great quantity of wastes from many drilling and/or production facilities.

Many different treatment technologies can potentially be applied to centralized treatment of oil and gas drilling wastes. The actual method used at the particular facility would depend on a number of factors. One of these factors is type of waste. Currently, some facilities are designed to treat solids for pH adjustment, dewatering, and solidification (muds and cuttings), while others are designed to treat produced waters, completion fluids, and stimulation fluids. Some facilities can treat a combination of wastes. Other factors determining treatment method include facility capacity, discharge options and requirements, solid waste disposal options, and other relevant State or local requirements.

Environmental Performance

Experience with centralized treatment is limited. Until recently, it was used only for treatment of offshore wastes. Its use in recent years for onshore wastes is commercially speculative, being principally a commercial response to the anticipated impacts of stricter State rules pertaining to oil and gas drilling and production waste. The operations have not been particularly successful as business ventures so far.

Commercial Landfarming

Description

Landfarming is a method for converting reserve pit waste material into soil-like material by bacteriological breakdown and through soil incorporation. The method can also be used to process production wastes, such as production tank bottoms, emergency pit cleanouts, and scrubber bottoms. Incorporation into soil uses dilution, biodegradation, chemical alteration, and metals adsorption mechanisms of soil and soil bacteria to reduce waste constituents to acceptable soil levels consistent with intended land use.

Solid wastes are distributed over the land surface and mixed with soils by mechanical means. Frequent turning or disking of the soil is necessary to ensure uniform biodegradation. Waste-to-soil ratios are normally about 1:4 in order to restrict concentrations of certain pollutants in the mixture, particularly chlorides and oil (Tucker 1985). Liquids can be applied to the land surface by various types of irrigation including sprinkler, flood, and ridge and furrow. Detailed landfarming design procedures are discussed in the literature (Freeman and Deuel 1984).

Landfarming methods have been applied to reserve pit wastes in commercial offsite operations. The technique provides both treatment and final disposition of salts, oil and grease, and solids. Landfarming may eventually produce large volumes of soil-like material that must be removed from the area to allow operations to continue.

Requirements for later reuse or disposal of this material must be determined separately.

Environmental Performance

Landfarming is generally done in areas large enough to incorporate the volume of waste to be treated. In commercial landfarming operations where the volume of materials treated within a given area is large, steps must be taken to ensure protection of surface and ground water. It is important, for instance, to minimize application of free liquids so as to reduce rapid transport of fluids through the soils.

The process is most suitable for the treatment of organics, especially the lighter fluid fractions that tend to distribute themselves quickly into the soil through the action of biodegradation. Heavy metals are also "treated" in the sense that they are adsorbed onto clay particles in the soil, presumably within a few feet of where they are applied; but the capacity of soils to accept metals is limited depending upon clay content. Similarly, the ability of the soil to accept chlorides and still sustain beneficial use is also limited.

Some States, such as Oklahoma and Kansas, prohibit the use of commercial landfarming of reserve pit wastes. Other States, such as Louisiana, allow reuse of certain materials treated at commercial landfarming facilities. Materials determined to meet certain criteria after treatment can be reused for applications such as daily sanitary

landfill covering or roadbed construction. When reusing landfarmed material, it is important that such material not adversely affect any part of the food chain.

Reconditioning and Reuse of Drilling Media

Description

Reconditioning and reuse of drilling media are currently practiced in a few well-defined situations. The first such situation involves the reconditioning of oil-based muds. This is a universal practice because of the high cost of oil used in making up this type of drilling media. A second situation involves the reuse of reserve pit fluids as "spud" muds, the muds used in drilling the initial shallow portions of a well in which lightweight muds can be used. A third situation involves the increased reuse of drilling fluid at one well, using more efficient solids removal. Less mud is required for drilling a single well if efficient solids control is maintained. Another application for reuse of drilling media is in the plugging procedure for well abandonment. Pumpable portions of the reserve pit are transported by vacuum truck to the well being closed. The muds are placed in the wellbore to prevent contamination of possibly productive strata and freshwater aquifers from saltwater strata. The ability to reuse drilling media economically varies widely with the distance between drilling operations, frequency and continuity of the drilling schedule, and compatibility between muds and formations among drill sites.

Environmental Performance

The above discussion raises the possibility of minimization of drilling fluids as an approach to limiting any potential environmental impacts of drilling-related wastes. Experience in reconditioning and reusing spud muds and oil-based muds does not provide any estimate of

specific benefits that might be associated with recycling or reuse of most conventional drilling muds. Benefits from mud recycling at the project level can be considerable. From a national perspective, benefits are unknown. The potential for at least some increased recycling and reuse appears to exist primarily through more efficient management of mud handling systems. Specific attempts to minimize the volume of muds used are discouraged, at present, by two factors: (1) drilling mud systems are operated by independent contractors, for whom sales of muds are a primary source of income, and (2) the central concern of all parties is successful drilling of the well, resulting in a general bias in favor of using virgin materials.

In spite of these economic disincentives, recent industry studies suggest that the benefits derived from decreasing the volume of drilling mud used to drill a single well are significant, resulting in mud cost reductions of as much as 30 percent (Amoco 1985).

PRODUCTION-RELATED WASTES

Waste Characterization

Produced Water

When oil and gas are extracted from hydrocarbon reservoirs, varying amounts of water often accompany the oil or gas being produced. This is known as produced water. Produced water may originate from the reservoir being produced or from waterflood treatment of the field (secondary recovery). The quantity of water produced is dependent upon the method of recovery, the nature of the formation being produced, and the length of time the field has been producing. Generally, the ratio of produced water to oil or gas increases over time as the well is produced.

Most produced water is strongly saline. Occasionally, chloride levels, and levels of other constituents, may be low enough (i.e., less

than 500 ppm chlorides) to allow the water to be used for beneficial purposes such as crop irrigation or livestock watering. More often, salinity levels are considerably higher, ranging from a few thousand parts per million to over 150,000 ppm. Seawater, by contrast, is typically about 35,000 ppm chlorides. Produced water also tends to contain quantities of petroleum hydrocarbons (especially lower molecular weight compounds), higher molecular weight alkanes, polynuclear aromatic hydrocarbons, and metals. It may also contain residues of biocides and other additives used as production chemicals. These can include coagulants, corrosion inhibitors, cleaners, dispersants, emulsion breakers, paraffin control agents, reverse emulsion breakers, and scale inhibitors.

Radioactive materials, such as radium, have been found in some oil field produced waters. Ra-226 activity in filtered and unfiltered produced waters has been found to range between 16 and 395 picocuries/liter; Ra-228 activity may range from 170 to 570 picocuries/liter (USEPA 1985). The ground-water standard for the Maximum Contaminant Level (MCL) for combined Ra-226 and Ra-228 is 5 picocuries/liter (40 CFR, Part 257, Appendix 1). No study has been done to determine the percentage of produced water that contains radioactive materials.

Low-Volume Production Wastes

Low-volume production-related wastes include many of the chemical additives discussed above in relation to drilling (see Table III-2), as well as production tank bottoms and scrubber bottoms.

Onsite Management Methods

Onsite management methods for production wastes include subsurface injection, the use of evaporation and percolation pits, discharge of produced waters to surface water, and storage.

Subsurface Injection

Description: Today, subsurface injection is the primary method for disposing of produced water from onshore operations, whether for enhanced oil recovery (EOR) or for final disposal. Nationally, an estimated 80 percent of all produced water is disposed of in injection wells permitted under EPA's Underground Injection Control (UIC) program under the authority of the Safe Drinking Water Act.[8] In the major oil-producing States, it is estimated that over 90 percent of production wastes are disposed of by this method. Subsurface injection may be done at injection wells onsite, offsite, or at centralized facilities. The mechanical design and procedures are generally the same in all cases.

In enhanced recovery projects, produced water is generally reinjected into the same reservoir from which the water was initially produced. Where injection is used solely for disposal, produced water is injected into saltwater formations, the original formation, or older depleted producing formations. Certain physical criteria make a formation suitable for disposal, and other criteria make a formation acceptable to regulatory authorities for disposal.

The sequence of steps by which waste is placed in subsurface formations may include:

- Separation of free oil and grease from the produced water;
- Tank storage of the produced water;
- Filtration;
- Chemical treatment (coagulation, flocculation, and possibly pH adjustment); and, ultimately,
- Injection of the fluid either by pumps or by gravity flow.

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8 API states that 80 to 90 percent of all produced water is injected in Class II wells.

By regulation, injection for the purpose of disposal must take place below all formations containing underground sources of drinking water (USDWs). Figure III-2 displays a typical disposal well pumping into a zone located below the freshwater table (Templeton and Associates 1980). The type of well often preferred by State regulatory agencies is the well specifically drilled, cased, and completed to accept produced water and other oil and gas production wastes. Another type of disposal well is a converted production well, the more prevalent type of disposal and enhanced recovery well. An injection well's location and age and the composition of injected fluids are the important factors in determining the level of mechanical integrity and environmental protection the well can provide.

Although it is not a very widespread practice, some produced water is disposed of through the annulus of producing wells. In this method, produced water is injected through the annular space between the production casing and the production tubing (see Figure III-3).[9] Injection occurs using little or no pressure. The disposal zone is shallower than the producing zone in this case. Testing of annular disposal wells is involved and expensive.

One method of testing the mechanical integrity of the casing used for annular injection, without removing the tubing and packer, is through the use of radioactive tracers and sensing devices. This method involves the pumping of water spiked with a low-level radioactive tracer into the injection zone, followed by running a radioactivity-sensing logging tool through the tubing string. This procedure should detect any shallow casing leaks or any fluid migration between the casing and the borehole. Most State regulatory agencies discourage annular injection and allow the practice only in small-volume, low-pressure applications.

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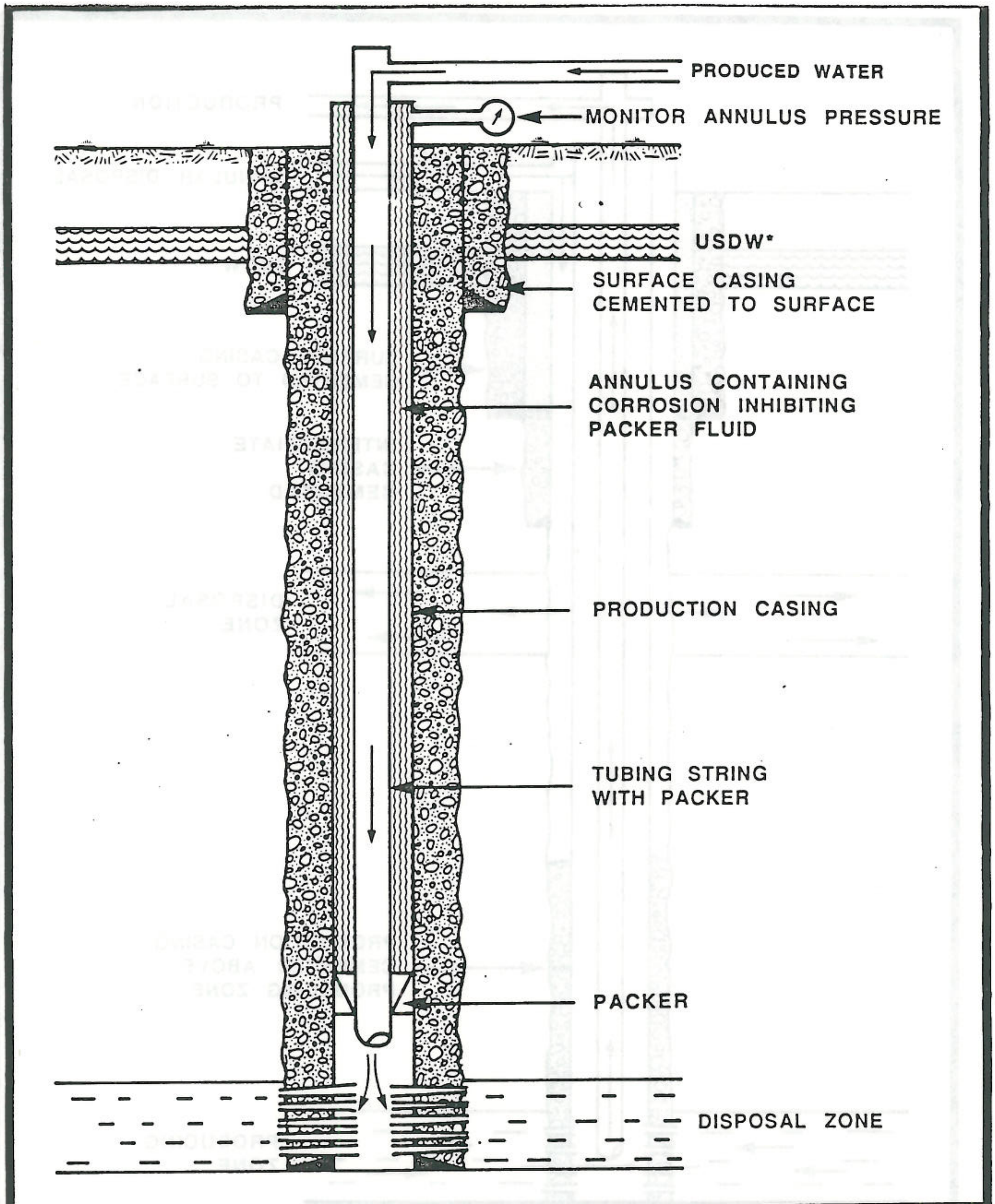
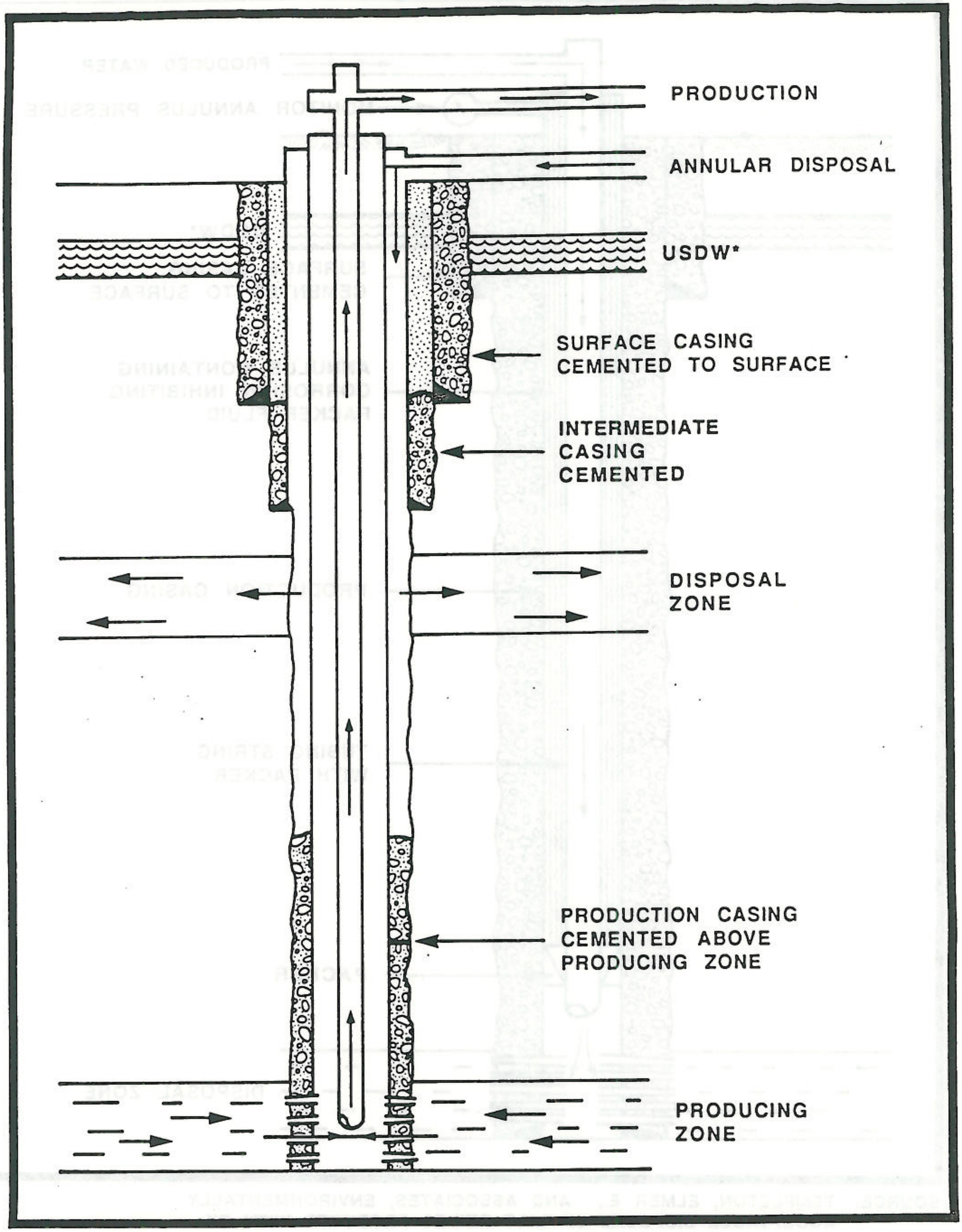
9 In the State of Ohio, produced water is gravity-fed into the annulus rather than being pumped.



SOURCE: TEMPLETON, ELMER E., AND ASSOCIATES, ENVIRONMENTALLY ACCEPTABLE DISPOSAL OF SALT BRINES PRODUCED WITH OIL AND GAS, JANUARY, 1980.

* UNDERGROUND SOURCE OF DRINKING WATER
NOTE: NOT TO SCALE

Figure III-2 Typical Produced Water Disposal Well Design



SOURCE: TEMPLETON, ELMER E., AND ASSOCIATES, ENVIRONMENTALLY ACCEPTABLE DISPOSAL OF SALT BRINES PRODUCED WITH OIL AND GAS, JANUARY, 1980.

* UNDERGROUND SOURCE OF DRINKING WATER
NOTE: NOT TO SCALE

Figure III-3 Annular Disposal Outside Production Casing

Environmental performance: From the environmental standpoint, the primary issue with disposal of produced waters is the potential for chloride contamination of arable lands and fresh water. Other constituents in produced water may also affect the quality of ground water. Because of their high solubility in water, there is no practical way to immobilize chlorides chemically, as can be done with heavy metals and many other pollutants associated with oil and gas production.

Injection of produced water below all underground sources of drinking water is environmentally beneficial if proper safeguards exist to ensure that the salt water will reach a properly chosen disposal horizon, which is sufficiently isolated from usable aquifers. This can be accomplished by injecting water into played-out formations or as part of a waterflooding program to enhance recovery from a field. Problems to be avoided include overpressurization of the receiving formation, which could lead to the migration of the injected fluids or native formation fluids into fresh water via improperly completed or abandoned wells in the pressurized area. Another problem is leaking of injected fluids into freshwater zones through holes in the tubing and casing.

The UIC program attempts to prevent these potential problems. The EPA UIC program requires periodic mechanical integrity tests (MITs) to detect leaks in casing and ensure mechanical integrity of the injection well. Such testing can detect performance problems if it is conscientiously conducted on schedule. The Federal regulations require that mechanical integrity be tested for at least every 5 years. If leaks are detected or mechanical integrity cannot be established during the testing of the well, the response is generally to suspend disposal operations until the well is repaired or to plug and abandon the well if repair proves too costly or inefficient. The Federal regulations also require that whenever a new well or existing disposal well is permitted, a one-quarter mile radius around the well must be reviewed for the presence of manmade or natural conduits that could lead to injected fluids or native brines leaving the injection zone. In cases where

improperly plugged or completed wells are found, the permit applicant must correct the problems or agree to limit the injection pressure. Major factors influencing well failure include the design, construction, and age of the well itself (converted producing wells, being older, are more likely to fail a test for integrity than newly constructed Class II injection wells); the corrosivity of the injected fluid (which varies chiefly in chloride content); and the injection pressure (especially if wastes are injected at pressures above specified permit limits).

Design, construction, operation, and testing: There is considerable variation in the actual construction of Class II wells in operation nationwide because many wells in operation today were constructed prior to enactment of current programs and because current programs themselves may vary quite significantly. The legislation authorizing the UIC program directed EPA to provide broad flexibility in its regulations so as not to impede oil and gas production, and to impose only requirements that are essential to the protection of USDWs. Similarly, the Agency was required to approve State programs for oil and gas wells whether or not they met EPA's regulations as long as they contained the minimum required by the Statute and were effective in protecting USDWs. For these reasons there is great variability in UIC requirements in both State-run and EPA-run programs. In general, requirements for new injection wells are quite extensive. Not every State, however, has required the full use of the "best available" technology. Furthermore, State requirements have evolved over time, and most injection wells operate with a lifetime permit. In practice, construction ranges from wells in which all USDWs are fully protected by two strings of casing and cementing, injection is through a tubing, and the injection zone is isolated by the packer and cement in the wellbore to shallow wells with one casing string, no packer, and little or no cement.

With respect to requirements for mechanical integrity testing of injection wells, Federal UIC requirements state that "an injection well

has mechanical integrity if: (1) there is no significant leak in the casing, tubing or packer; and (2) there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore." Translation of these general requirements into specific tests varies across States.

In addition to initial pressure testing prior to operation of injection wells, States (including those that do not have primacy under the UIC program) also require monitoring or mechanical integrity tests of Class II injection wells at least once every 5 years. In lieu of such a casing pressure test, the operator may, each month, monitor or record the pressure in the casing/tubing annulus during actual injection and report the pressure on a yearly basis.

To date, about 70 percent of all Class II injection wells have been tested nationwide, though statistics vary across EPA Regions. Data on these tests available at the Federal level are not highly detailed. Although Federal legislation lists a number of specific monitoring requirements (such as monitoring of injection pressures, volumes, and nature of fluid being injected and 5-year tests for mechanical integrity), technical information such as injection pressure and waste characterization is not reported at the Federal level. (These data are often kept at the State level.) Until recently, Federal data on mechanical integrity tests listed only the number of wells passing and failing within each State, without any explanation of the type of failure or its environmental consequences.

For injection wells used to access underground hydrocarbon storage and enhanced recovery, a well may be monitored on a field or project basis rather than on an individual well basis by manifold monitoring, provided the owner or operator demonstrates that manifold monitoring is

comparable to individual well monitoring. Manifold monitoring may be used in cases where facilities consist of more than one injection well and operate with a common manifold. Separate monitoring systems for each well are not required provided the owner or operator demonstrates that manifold monitoring is comparable to individual well monitoring.

Under the Federal UIC program, all ground water with less than 10,000 mg/L total dissolved solids (TDS) is protected. Casing cemented to the surface is one barrier against contamination of USDWs. State programs vary in their requirements for casing and cementing. For example, Texas requires surface casing in strata with less than 3,000 ppm TDS; Louisiana, less than 1,500 ppm TDS; New Mexico, less than 5,000 ppm TDS. However, all wells must be designed to protect USDWs through a combination of surface casing, long string or intermediate casing, cementing, and geologic conditions.

<u>Proximity to other wells and to protected aquifers</u>: When a new injection well is drilled or an existing well is converted for injection, the area surrounding the site must be inspected to determine whether there are any wells of record that may be unplugged or inadequately plugged or any active wells that were improperly completed. The radius of concern includes that area within which underground pressures will be increased. All States have adopted at least the minimum Federal requirement of a one-quarter mile radius of review; however, the Agency is concerned that problems may still arise in instances where undocumented wells (such as dry holes) exist or where wells of record cannot be located.

States typically request information on the permit application about the proximity of the injection well to potable aquifers or to producing wells, other injection wells, or abandoned oil- or gas-producing wells

within a one-quarter mile radius. In Oklahoma, for instance, additional restrictions are placed on UIC Class II wells within one-half mile of an active or reserve municipal water supply well unless the applicant can "prove by substantial evidence" that the injection well will not pollute a municipal water supply.

Although these requirements exist, it is important to recognize the following:

- Policy on review of nearby wells varies widely from State to State, and the injection well operator has had only a limited responsibility to identify possible channels of communication between the injection zone and freshwater zones.

- Many injection operations predate current regulations on the review of nearby wells and, because of "grandfather" clauses, are exempt.

Operation and maintenance: Incentives for compliance with applicable State or Federal UIC requirements will tend to vary according to whether a well is used for enhanced recovery or purely for waste disposal. Wells used for both purposes may be converted production wells or wells constructed specifically as Class II wells.

In order for enhanced recovery to be successful, it is essential for operators to ensure that fluids are injected into a specific reservoir and that pressures within the producing zone are maintained by avoiding any communication between that zone and others. Operators therefore have a strong economic incentive to be scrupulous in operating and maintaining Class II wells used for enhanced recovery.

On the other hand, economic incentives for careful operation of disposal wells may not be as strong. The purpose here is to dispose of fluids. The nature of the receiving zone itself, although regulated by State or Federal rules, is not of fundamental importance to the well

operator as long as the receiving formation is able to accept injected fluids. Wells used for disposal are often older, converted production wells and may be subject to more frequent failures.

Evaporation and Percolation Pits

Description: Evaporation and percolation pits (see discussion above under "Reserve Pits") are also used for produced water disposal. An evaporation pit is defined as a surface impoundment that is lined by a clay or synthetic liner. An evaporation/percolation pit is one that is unlined.

Environmental performance: Evaporation of produced water can occur only under suitable climatic conditions, which limits the potential use of this practice to the more arid producing areas within the States. Percolation of produced water into soil has been allowed more often in areas where the ground water underlying the pit area is saline and is not suitable for use as irrigation water, livestock water, or drinking water. The use of evaporation and percolation pits has the potential to degrade usable ground water through seepage of produced water constituents into unconfined, freshwater aquifers underlying such pits.[10]

Discharge of Produced Waters to Surface Water Bodies

Description: Discharge of produced water to surface water bodies is generally done under the NPDES permit program. Under NPDES, discharges are permitted for (1) coastal or tidally influenced water, (2) agricultural and wildlife beneficial use, and (3) discharge of produced water from stripper oil wells to surface streams. Discharge under NPDES often occurs after the produced water is treated to control

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10 This phenomenon is documented in Chapter IV.

pH and minimize a variety of common pollutants, such as oil and grease, total dissolved solids, and sulfates. Typical treatment methods include simple oil and grease separation followed by a series of settling and skimming operations.

Environmental performance: Direct discharge of produced waters must meet State or Federal permit standards. Although pollutants such as total organic carbon are limited in these discharges, large volumes of discharges containing low levels of such pollutants may be damaging to aquatic communities.[11]

Other Production-Related Pits

Description: A wide variety of pits are used for ancillary storage and management of produced waters and other production-related wastes. These can include:[12]

1. Basic sediment pit: Pit used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank. (Also referred to as a burn pit.)
2. Brine pit: Pit used for storage of brine used to displace hydrocarbons from an underground hydrocarbon storage facility.
3. Collecting pit: Pit used for storage of produced water prior to disposal at a tidal disposal facility, or pit used for storage of produced water or other oil and gas wastes prior to disposal at a disposal well or fluid injection well. In some cases, one pit is both a collecting pit and a skimming pit.
4. Completion/workover pit: Pit used for storage or disposal of spent completion fluids, workover fluids, and drilling fluid; silt; debris; water; brine; oil; scum; paraffin; or other materials that have been cleaned out of the wellbore of a well being completed or worked over.

11 This phenomenon is documented in Chapter IV.

12 List adapted from Texas Railroad Commission Rule 8, amended March 5, 1984.

5. Emergency produced water storage pit: Pit used for storage of produced water for a limited period of time. Use of the pit is necessitated by a temporary shutdown of a disposal well or fluid injection well and/or associated equipment, by temporary overflow of produced water storage tanks on a producing lease, or by a producing well loading up with formation fluids such that the well may die. Emergency produced water storage pits may sometimes be referred to as emergency pits or blowdown pits.

6. Flare pit: Pit that contains a flare and that is used for temporary storage of liquid hydrocarbons that are sent to the flare during equipment malfunction but are not burned. A flare pit is used in conjunction with a gasoline plant, natural gas processing plant, pressure maintenance or repressurizing plant, tank battery, or well.

7. Skimming pit: Pit used for skimming oil off produced water prior to disposal of produced water at a tidal disposal facility, disposal well, or fluid injection well.

8. Washout pit: Pit located at truck yard, tank yard, or disposal facility for storage or disposal of oil and gas waste residue washed out of trucks, mobile tanks, or skid-mounted tanks.[13]

The Wyoming Oil and Gas Conservation Commission would add pits that retain fluids for disposal by evaporation such as pits used for gas wells or pits used for dehydration facilities.

Environmental performance: All of these pits may cause adverse environmental impact if their contents leach, if they are improperly closed or abandoned, or if they are used for improper purposes. Although they are necessary and useful parts of the production process, they are subject to potential abuse. An example would be the use of an emergency pit for disposal (through percolation or evaporation) of produced water.

Offsite Management Methods

Road or Land Applications

Description: Untreated produced water is sometimes disposed of by application to roads as a deicing agent or for dust control.

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13 The Alaska Department of Environmental Conservation questions whether pits described in Items 1, 6, and 8 should be exempt under RCRA.

Environmental performance: Road or land application of produced waters may cause contamination of ground water through leaching of produced water constituents to unconfined freshwater aquifers. Many States do not allow road or land application of produced waters.

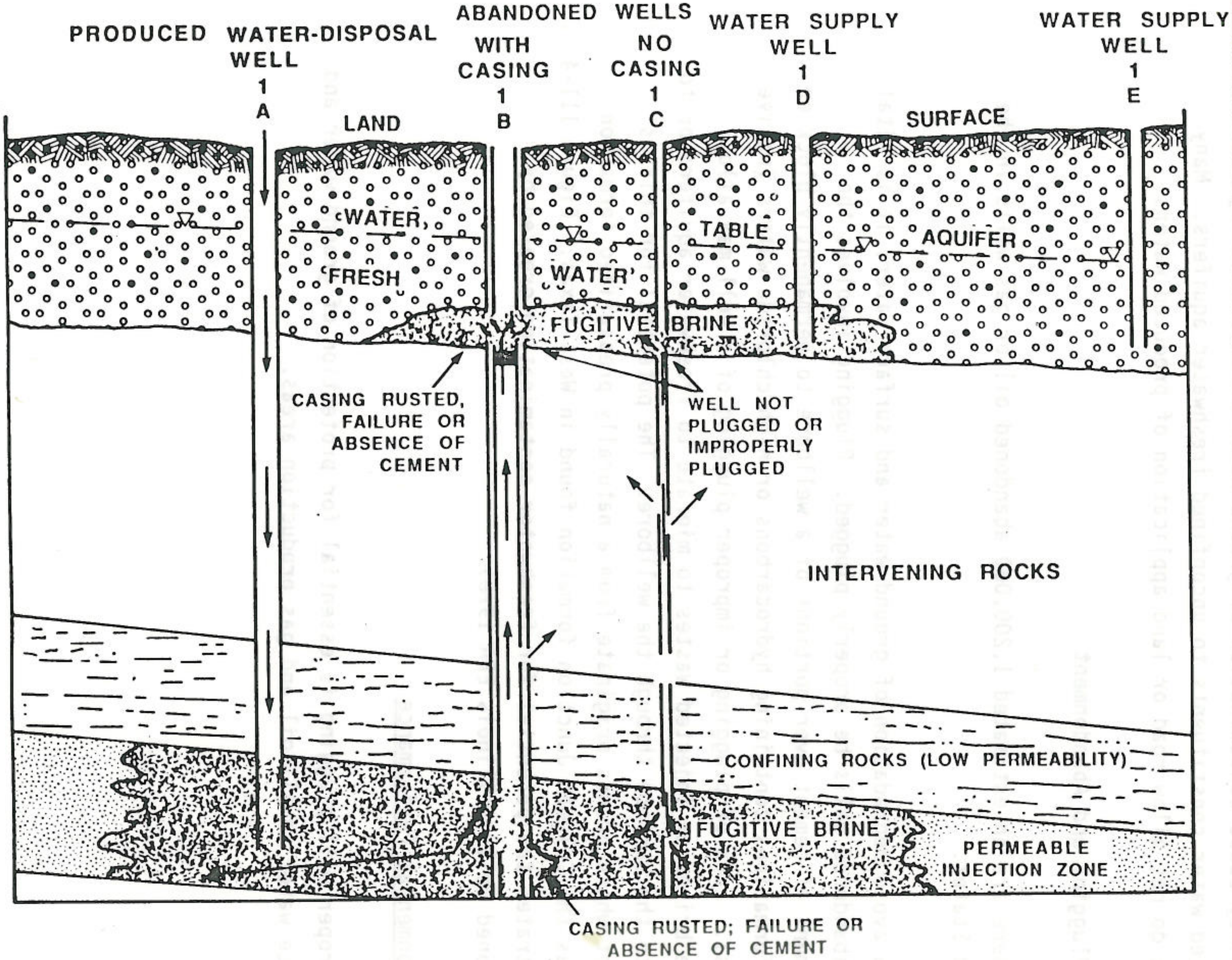
Well Plugging and Abandonment

There are an estimated 1,200,000 abandoned oil or gas wells in the United States.

To avoid degradation of ground water and surface water, it is vital that abandoned wells be properly plugged. Plugging involves the placement of cement over portions of a wellbore to permanently block or seal formations containing hydrocarbons or high-chloride waters (native brines). Lack of plugging or improper plugging of a well may allow native brines or injected wastes to migrate to freshwater aquifers or to come to the surface through the wellbore. The potential for this is highest where brines originate from a naturally pressurized formation such as the Coleman Junction formation found in West Texas. Figure III-4 illustrates the potential for freshwater contamination created by abandoned wells (Illinois EPA 1978).

Environmental Performance

Proper well plugging is essential for protection of ground water and surface water in all oil and gas production areas.



SOURCE: ILLINOIS EPA, ILLINOIS OIL FIELD BRINE DISPOSAL ASSESSMENT: STAFF REPORT, NOVEMBER 1978.

NOTE: NOT TO SCALE

Figure III-4 Pollution of a Fresh Water Aquifer Through Improperly

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CHAPTER IV

DAMAGE CASES

INTRODUCTION

Purpose of the Damage Case Review

The damage case study effort conducted for this report had two principal objectives:

To Respond to the Requirements of Section 8002(m)(C)

The primary objective was to respond to the requirements of Section 8002(m) of RCRA, which require EPA to identify documented cases that prove or have caused danger to human health and the environment from surface runoff or leachate. In interpreting this passage, EPA has emphasized the importance of strict documentation of cases by establishing a test of proof (discussed below) that all cases were required to pass before they could be included in this report. In addition, EPA has emphasized development of recent cases that illustrate damages created by current practices under current State regulations. This has been complicated in some instances by recent revisions to regulatory requirements in some States. The majority of cases presented in this chapter (58 out of 61) occurred during the last 5 years. Historical damages that occurred under prior engineering practices or under previous regulatory regimes have been excluded unless such historical damages illustrate health or environmental problems that the Agency believes should be brought to the attention of Congress now.[1] The overall objective is to present documented cases that show reasonably clear links of cause and effect between waste management practices and resulting damages, and to identify cases where damages have been most significant in terms of human health or environmental impacts.

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1 The primary example of this is the problem of abandoned wells, discussed at length under Miscellaneous Issues below. The abandoned well problem results for the most part from inadequate past plugging practices. Although plugging practices have since been improved under State regulations, associated damages to health and the environment are continuing.

To Provide an Overview of the Nature of Damages Associated with Oil and Gas Exploration, Development, or Production Activities

In the course of accumulating damage cases, EPA has acquired a significant amount of information that has provided helpful insights into the nature of damages.

Methodology for Gathering Damage Case Information

The methodology for identifying, collecting, and processing damage cases was originally presented in draft form in the Technical Report published on October 31, 1986. The methodology, which differs minimally from the draft, is outlined below.

Information Categories

The damage case effort attempted to collect and record several categories of information on each case. Initially, this information was organized into a data base from which portions of cases were drawn for use in the final report. Categories of information were as follows:

1. Characterization of specific damage types: For each case, the environmental medium involved was determined (ground water, surface water, or land), along with the type of incident and characterization of damage. Only cases with documented damage were included. Types of potential health or environmental damages of interest are shown on Table IV-1.

2. The size and location of the site: Sites were located by nearest town and by county. Where significant hydrogeological or other pertinent factors are known, they were included; however, this type of information has been difficult to gather for all cases.

3. The operating status of the facility or site: All pertinent factors relating to the site's status (active, inactive, in process of shutdown, etc.) have been noted.

Table IV-1 Types of Damage of Concern to This Study

1. Human Health Effects (acute and chronic): While there are some instances where contamination has resulted in cases of acute adverse human health effects, such cases are difficult to document. Levels of pollution exposure caused by oil and gas operations are more likely to be in ranges associated with chronic carcinogenic and noncarcinogenic effects.

2. Environmental Effects: Impairment of natural ecosystems and habitats, including contaminating of soils, impairment of terrestrial or aquatic vegetation, or reduction of the quality of surface waters.

3. Effects on Wildlife: Impairment to terrestrial or aquatic fauna; types of damage may include reduction in species' presence or density, impairment of species' health or reproductive ability, or significant changes in ecological relationships among species.

4. Effects on Livestock: Morbidity or mortality of livestock, impairment in the marketability of livestock, or any other adverse economic or health-based impact on livestock.

5. Impairment of Other Natural Resources: Contamination of any current or potential source of drinking water, disruption or lasting impairment to agricultural lands or commercial crops, impairment of potential or actual industrial use of land, or reduction in current or potential use of land.

4. Identification of the type and volume of waste involved: While the type of waste involved has been easy to define, volumes often have not.

5. Identification of waste management practices: For each incident, the waste management practices associated with the incident have been presented.

6. Identification of any pertinent regulations affecting the site: State regulations in force across the oil- and gas-producing States are discussed at length in Appendix A. Since it would be unwieldy to attempt to discuss all pertinent regulations in relation to each site, each documented case includes a section on Compliance Issues that discusses significant regulatory issues associated with each incident as reported by sources or contacts.[2] In some cases, interpretations were necessary.

7. Type of documentation available: All documentation available for each case was included to the extent possible. For a few cases, documentation is extensive.

For the purpose of this report, the data base was condensed and is presented in Appendix C.

Sources and Contacts

No attempt was made to compile a complete census of current damage cases. States from which cases were drawn are listed on Table IV-2. As evident from the table, resources did not permit gathering of cases from all States.

Within each of the States, every effort was made to contact all available source categories listed in the Technical Report (see Table IV-3). Because time was extremely limited, the effort relied principally on information available through relevant State and local agencies and

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[2] All discussions have been reviewed by State officials and by any other sources or contacts who provided information on a case.

Table IV-2 States From Which Case Information Was Assembled

1. Alaska
2. Arkansas
3. California
4. Colorado
5. Kansas
6. Louisiana
7. Michigan
8. New Mexico
9. Ohio
10. Oklahoma
11. Pennsylvania
12. Texas
13. West Virginia
14. Wyoming

Table IV-3 Sources of Information Used in Developing Damage Cases

1. Relevant State or Local Agencies: including State environmental agencies; oil and gas regulatory agencies; State, regional, or local departments of health; and other agencies potentially knowledgeable about damages related to oil and gas operations.

2. EPA Regional Offices

3. Bureau of Land Management

4. Forest Service

5. Geological Survey

6. Professional or trade associations

7. Public interest or citizens' groups

8. Attorneys engaged in litigation

on contacts provided through public interest or citizens' groups. In some instances, cases were developed through contacts with private attorneys directly engaged in litigation. Because these nongovernmental sources often provided information on incidents of which State agencies were unaware, such cases were sometimes undocumented at the State level. State agencies were, however, provided with review drafts of case write-ups. They, in turn, provided extensive additional information and comments.

Case Study Development

Virtually all of the data used here were gathered through direct contacts with agencies and individuals, or through followup to those contacts, rather than through secondary references. For each State, researchers first contacted all State agencies that play a significant role in the regulation of oil or gas operations and set up appointments for field visits. At the same time, contacts and appointments were made where possible with local citizens' groups and private attorneys in each State. Visits were made in the period between December 1986 and February 1987. During that time, researchers gathered actual documentation and made as many additional contacts as possible.

Test of Proof

All cases were classified according to whether they met one or more formal tests of proof, a classification that was to some extent judgmental. Three tests were used, and cases were considered to meet the documentation standards of 8002(m)(C) if they met one or more of them.

The tests were as follows:

1. <u>Scientific investigation:</u> A case could meet documentation standards if damages were found to exist as part of the findings of a scientific study. Such studies could be extensive formal investigations supporting litigation or a State enforcement action, or they could, in some instances, be the results of technical tests (such as monitoring of wells) if such tests (a) were conducted with State-approved quality control procedures, and (b) revealed contamination levels in excess of an applicable State or Federal standard or guideline (such as a drinking water standard or water quality criterion).

2. <u>Administrative ruling:</u> A case could meet documentation standards if damages were found to exist through a formal administrative finding, such as the conclusions of a site report by a field investigator, or through existence of an enforcement action that cited specific health or environmental damages.

3. <u>Court decision:</u> The third way in which a case could be accepted was if damages were found to exist through the ruling of a court or through an out-of-court settlement.

EPA considered the possibility of basing its damage case review solely on cases that have been tried in court and for which damage determinations have been made by jury or judicial decision. This approach was rejected for a variety of reasons. First and most important, EPA wanted wherever possible to base its damage case work on scientific evidence and on evidence developed by States as part of their own regulatory control programs. Since States are the most important entity in controlling the environmental impacts of this industry, the administrative damage determinations they make are of the utmost concern to EPA. Second, comparatively few cases are litigated, and many litigated cases, perhaps a majority, are settled out of court and their records sealed through agreements between plaintiffs and defendants. Third, as data collected for this report indicate, many litigated cases are major cases in which the plaintiff may be a corporation or a comparatively wealthy landowner with the resources necessary to develop

the detailed evidence necessary to successfully litigate a private suit (see damage case LA 65 on pages IV-78 and IV-79). Private citizens rarely bring cases to court because court cases are expensive to conduct, and most of these cases are settled out of court.

Review by State Groups and Other Sources

All agencies, groups, and individuals who provided documentation or who have jurisdiction over the sites in any specific State were sent draft copies of the damage cases. Because of the tight schedule for development of the report, there was limited time available for damage case review. Their comments were incorporated to the extent possible; EPA determined which comments should be included.

Limitations of the Methodology and Its Results

Schedule for Collection of Damage Case Information

The time period over which the damage case study work occurred was short, covering portions of three consecutive months. In addition, much of the field research was arranged or conducted over the December 1986-January 1987 holiday period, when it was often difficult to make contacts with State agency representatives or private groups. To the extent that resources permitted, followup visits were made to fill gaps. Nevertheless, coverage of some States had to be omitted entirely, and coverage in others (particularly Oklahoma) was limited.

Limited Number of Oil- and Gas-Producing States in Analysis

Of the States originally intended to be covered as discussed in the Technical Report, several were omitted from coverage; however, States

visited account for a significant percentage of U.S. oil and gas production (see Table IV-2).

Difficulty in Obtaining a Representative Sample

In general, case studies are used to gain familiarity with ranges of issues involved in a particular study topic, not to provide a statistical representation of damages. Therefore, although every attempt was made to produce representative cases of damages associated with oil and gas operations, this study does not assert that its cases are a statistically representative record of damages in each State. Even if an attempt had been made to create a statistically valid study set, such as by randomly selecting drilling operations for review, it would have been difficult for a number of practical reasons.

First, record keeping varies significantly among States. A few States, such as Ohio, have unusually complete and up-to-date central records of enforcement actions and complaints. More often, however, enforcement records are incomplete and/or distributed throughout regional offices within the State. Schedules were such that only a few offices, usually only the State's central offices, were visited by researchers. Furthermore, their ability to collect files at each office was limited by the time available on site (usually 1 day, but never more than 3 days) and by the ability of each State to spare staff time to assist in the research. The number of cases found at each office and the amount of material gathered were influenced strongly by these constraints.

Second, very often damage claims against oil and gas operators are settled out of court, and information on known damage cases has often been sealed through agreements between landowners and oil companies.

This is typical practice, for instance, in Texas. In some cases, even the records of well-publicized damage incidents are almost entirely unavailable for review. In addition to concealing the nature and size of any settlement entered into between the parties, impoundment curtails access to scientific and administrative documentation of the incident.

A third general limitation in locating damage cases is that oil and gas activities in some parts of the country are in remote, sparsely populated, and unstudied areas. In these areas, no significant population is present to observe or suffer damages, and access to sites is physically difficult. To systematically document previously unreported damages associated with operations in more remote areas would have required an extensive original research project far beyond the resources available to this study.

Organization of This Presentation

As noted throughout this report, conditions affecting exploration, development, and production of oil and gas vary extensively from State to State, and by regions within States. While it would be logical to discuss damage cases on a State-by-State basis, the following discussion is organized according to the zones defined for other purposes in this project. Within each zone the report presents one or more categories of damages that EPA has selected as fairly illustrative of practices and conditions within that zone, focusing principally on cases of damage associated with management of high-volume wastes (drilling fluids and produced waters). Wherever possible, State-specific issues are discussed as well.

At the end of this chapter are a number of miscellaneous categories of damage cases that, although significant and well-documented, are associated either with management of lower volume exempt wastes or with types of damage not immediately related to management of wastes from current field operations. Such categories include damages caused by unplugged or improperly plugged abandoned wells.

NEW ENGLAND

The New England zone includes Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, and Connecticut. No significant oil and gas are found in this zone, and no damage cases were collected.

APPALACHIA

The Appalachian zone includes Delaware, Kentucky, Maryland, New Jersey, New York, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. Many of these States have minimal oil and gas production. Damage cases were collected from Ohio, West Virginia, and Pennsylvania.

Operations

Oil and gas production in the Appalachian Basin tends to be marginal, and operations are often low-budget efforts. Funds for proper maintenance of production sites may be limited. Although the absolute amount of oil produced in the Appalachian zone is small in comparison with the rest of the country, the produced water-to-product ratios are typically very high and produced waters contain high concentrations of chlorides.[3]

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3 David Flannery, on behalf of various oil and gas trade organizations, states that "...in absolute terms, the discharge of produced water from wells in the Appalachian states is small."

In West Virginia in 1985, 1,839 new wells were completed at an average depth of 4,270 feet. Only 18 exploratory wells were drilled in that year. In Pennsylvania 4,627 new wells were completed in 1985 to an average depth 2,287 feet; 59 exploratory wells were drilled in that year. Activity in Ohio is developmental rather than exploratory, with only 78 exploratory wells drilled in 1985 out of a total of 6,297 wells completed. The average depth of a new well in 1985 was 3,760 feet.

Types of Operators

Oil and gas production in the Appalachian Basin is dominated by small operators, some well-established, some new to the industry. Major companies still hold leases in some areas. Since most extraction in this zone is economically marginal, many operators are susceptible to market fluctuations.

Major Issues

Contamination of Ground Water from Reserve Pits

Damage case incidents resulting from unlined reserve pits, with subsequent migration of contaminants into ground water, are found in the State of Ohio.

> In 1982, drilling activities of an unnamed oil and gas company contaminated the well that served a house and barn owned by a Mr. Bean, who used the water for his dairy operations. Analysis done on the water well by the Ohio Department of Agriculture found high levels of barium, iron, sodium, and chlorides. (Barium is a common constituent of drilling mud.) Because the barium content of the water well exceeded State standards, Mr. Bean was forced to shut down his dairy operations. Milk produced at the Bean farm following contamination of the water well contained 0.63 mg/L of barium. Concentrations of chlorides, barium, iron, sodium, and other residues in the water well were above the U.S. EPA's Secondary Drinking Water Standards. Mr. Bean drilled a new well, which also became contaminated. As of September 1984, Mr. Bean's water

well was still showing signs of contamination from the drilling-related wastes. It is not known whether Mr. Bean was able to recover financially from the disruption of his dairy business. (OH 49)[4]

This case is a violation of current Ohio regulations regarding drilling mud and produced waters.

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Illegal Disposal of Oil Field Wastes in Ohio

Illegal disposal of oil field wastes is a problem in Ohio, as elsewhere, but the State is making an aggressive effort to increase compliance with State waste disposal requirements and is trying to maintain complete and up-to-date records. The State has recently banned all saltwater disposal pits. A legislative initiative during the spring of 1987 attempted to overturn the ban. The attempt was unsuccessful.

The Miller Sand and Gravel Co., though an active producer of sand and gravel, has also served as an illegal disposal site for oil field wastes. An investigation by the Ohio Department of Natural Resources (DNR) found that the sand and gravel pits and the surrounding swamp were contaminated with oil and high-chloride produced waters. Ohio inspectors noted a flora kill of unspecified size. Ohio Department of Health laboratory analysis of soil and liquid samples from the pits recorded chloride concentrations of 269,000 mg/L. The surrounding swamp chloride concentrations ranged from 303 mg/L (upstream from the pits) to 60,000 mg/L (area around the pits). This type of discharge is prohibited by State regulations. (OH 45)[5]

This discharge was a violation of State regulations.

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[4] References for case cited: Ohio EPA, Division of Public Water Supply, Northeast District Office, interoffice communication from E. Mohr to M. Hilovsky describing test results on Mr. Bean's water well, 7/21/86. Letters from E. Mohr, Ohio EPA, to Mr. Bean and Mr. Hart explaining water sampling results, 10/20/82. Letter from Miceli Dairy Products Co. to E. Mohr, Ohio EPA, explaining test results from Mr. Bean's milk and water well. Letters from E. Mohr, Ohio EPA, to Mr. Bean explaining water sampling results from tests completed on 10/7/82, 2/2/83, 10/25/83, 6/15/84, 8/3/84, and 9/17/84. Generalized stratigraphic sequence of the rocks in the Upper Portion of the Grand River Basin.

[5] References for case cited: Ohio EPA, Division of Wastewater Pollution Control, Northeast District Office, interoffice communication from E. Mohr to D. Hasbrauck, District Chief, concerning the results from sampling at the sand and gravel site. Ohio Department of Health, Environmental Sample Submission Reports from samples taken on 6/22/82.

Equity Oil & Gas Funds, Inc., operates Well #1 on the Engle Lease, Knox County. An Ohio DNR official inspected the site on April 5, 1985. There were no saltwater storage tanks on site to collect the high-chloride produced water that was being discharged from a plastic hose leading from the tank battery into a culvert that, in turn, emptied into a creek. The inspector took photos and samples. Both produced water and oil and grease levels were of sufficient magnitude to cause damage to flora and fauna, according to the notice of violation filed by the State. The inspector noted that a large area of land along the culvert had been contaminated with oil and produced water. The suspension order indicated that the "...violations present an imminent danger to public health and safety and are likely to result in immediate and substantial damage to natural resources." The operator was required by the State to "...restore the disturbed land surface and remove the oil from the stream in accordance with Section 1509.072 of Ohio Revised Statutes...." (OH 07)[6]

This was an illegal discharge that violated Ohio regulations.

In another case:

Zenith Oil & Gas Co. operated Well #1 in Hopewell Township. The Ohio DNR issued a suspension order to Zenith in March of 1984 after State inspectors discovered produced water discharges onto the surrounding site from a breech in a produced water pit and pipe leading from the pit. A Notice of Violation had been issued in February 1984, but the violations were still in effect in March 1984. A State inspection of an adjacent site, also operated by Zenith Oil & Gas Co., discovered a plastic hose extending from one of the tank batteries discharging high-chloride produced water into a breached pit and onto the site surface. Another tank was discharging produced water from an open valve directly onto the site surface. State inspectors also expressed concern about lead and mercury contamination from the discharge. Lead levels in the discharge were 2.5 times the accepted level for drinking water, and mercury levels were 925 times the acceptable levels for drinking water, according to results filed for the State by a private laboratory. The State issued a suspension order stating that the discharge was "...causing contamination and pollution..." to the surface and subsurface soil, and in order to remedy the problem the operator would have to restore the disturbed land. (Ohio no longer allows the use of produced water disposal pits.) (OH 12)[7]

This was an illegal discharge that violated Ohio regulations.

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6 References for case cited: The Columbus Water and Chemical Testing Lab, lab reports. Ohio Department of Natural Resources, Division of Oil and Gas, Notice of Violation, 5/5/85.

7 References for case cited: Ohio Department of Natural Resources, Division of Oil and Gas, Suspension Order #84-07, 3/22/84. Muskingum County Complaint Form. Columbus Water and Chemical Testing Lab sampling report.

Contamination of Ground Water from Annular Disposal of Produced Water

Ohio allows annular disposal of produced waters. This practice is not widely used elsewhere because of its potential for creating ground-water contamination. Produced water containing high levels of chlorides tends to corrode the single string of casing protecting ground water from contamination during annular disposal. Such corrosion creates holes in a well's casing that can allow migration of produced water into ground water. Under the Federal UIC program, Ohio requires operators of annular disposal wells to conduct radioactive tracer surveys to determine whether produced water is being deposited in the correct formations. Tracer surveys are more expensive than conventional mechanical integrity tests for underground injection wells, and only 2 percent of all tracer surveys were witnessed by DNR inspectors in 1985.

The Donofrio well was a production oil well with an annular disposal hookup fed by a 100-bbl produced water storage tank. In December 1975, shortly after completion of the well, tests conducted by the Columbus Water and Chemical Testing Lab on the Donofrio residential water well showed chloride concentrations of 4,550 ppm. One month after the well contamination was reported, several springs on the Donofrio property showed contamination from high-chloride produced water and oil, according to Ohio EPA inspections. On January 8, 1976, Ohio EPA investigated the site and reported evidence of oil overflow from the Donofrio well production facility, lack of diking around storage tanks, and the presence of several produced water storage pits. In 1986, 11 years after the first report of contamination, a court order was issued to disconnect the annular disposal lines and to plug the well. The casing recovered from the well showed that its condition ranged from fair to very poor. The casing was covered with rust and scale, and six holes were found.[8] (OH 38)[9]

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8 Comments in the Docket by David Flannery and American Petroleum Institute (API) pertain to OH 38. Mr. Flannery states that "...the water well involved in that case showed contamination levels which predated the commencement of annular disposal...." EPA believes this statement refers to bacterial contamination of the well discovered in 1974. (EPA notes that the damage case discusses chloride contamination of the water well, not bacterial contamination.)

9 References for case cited: Ohio Department of Natural Resources, Division of Oil and Gas, interoffice communication from M. Sharrock to S. Kell on the condition of the casing removed from the Donofrio well. Communication from Attorney General's Office, E.S. Post, discussing court order to plug the Donofrio well. Perry County Common Pleas Court Case #19262. Letter from R.M. Kimball, Assistant Attorney General, to Scott Kell, Ohio Department of Natural Resources, presenting case summary from 1974 to 1984. Ohio Department of Health lab sampling reports from 1976 to 1985. Columbus Water and Chemical Testing Lab, sampling reports from 12/1/75, 7/27/84, and 8/3/84.

This well could not pass the current criteria for mechanical integrity under the UIC program.

An alternative to annular disposal of oil field waste is underground injection in Class II wells, using tubing and packer, but these Class II disposal wells are significantly more expensive than annular disposal operations.

<u>Illegal Disposal of Oil and Gas Waste in West Virginia</u>

Environmental damage from illegal disposal of wastes associated with drilling and production is by far the most common type of problem in West Virginia. Results of illegal disposal include fish kills, vegetation kills, and death of livestock from drinking polluted water. Fluids illegally disposed of include oil, produced waters of up to 180,000 ppm chlorides, drilling fluids, and fracturing fluids that can have a pH of as low as 3.0 (highly acidic).

Illegal disposal in this State takes many forms, including draining of saltwater holding tanks into streams, breaching of reserve pits into streams, siphoning of pits into streams, or discharging of vacuum truck contents into fields or streams.

Enforcement is difficult both because of limited availability of State inspection and enforcement personnel and because of the remote location of many drill sites (see Table VII-7). Many illegal disposal incidents come to light through complaints from landowners or anonymous informers.

Beginning in 1979, Allegheny Land and Mineral Company of West Virginia operated a gas well, #A-226, on the property of Ray and Charlotte Willey. The well was located in a corn field where cattle were fed in winter, and within 1,000 feet of the Willey's residence. The well was also adjacent to a stream known as the Beverlin Fork. Allegheny Land and Mineral operated another gas well above the residence known as the #A-306, also located on property owned by the Willeys. Allegheny Land and Mineral maintained open reserve pits and an open waste ditch, which ran into Beverlin Fork. The ditch served to dispose of produced water, oil, drip gas, detergents, fracturing fluids, and waste production chemicals. Employees of the company told the Willeys that fluids in the pits were safe for their livestock to drink.

The Willeys alleged that their cattle drank the fluid in the reserve pit and became poisoned, causing abortions, birth defects, weight loss, contaminated milk, and death. Hogs were also allegedly poisoned, resulting in infertility and pig still-births, according to the complaint filed in the circuit court of Doddridge County, by the Willeys, against Allegheny Land and Mineral. The Willeys claimed that the soil on the farm was contaminated, causing a decrease in crop production and quality; that the ground water of the farm was contaminated, polluting the water well from which they drew their domestic water supply; and that the value of their real estate had been diminished as a result of these damages. Laboratory tests of soil and water from the property confirmed this contamination. The Willeys incurred laboratory expenses in having testing done on livestock, soil, and water. A judgment filed in the circuit court of Doddridge County was entered in 1983 wherein the Willeys were awarded a cash settlement in court for a total of $39,000 plus interest and costs.[10] (WV 18)[11]

This practice would violate current West Virginia regulations.

On February 23, 1983, Tom Ancona, a fur trapper, filed a complaint concerning a fish kill on Stillwell Creek. A second complaint was also filed anonymously by an employee of Marietta Royalty Co. Ancona, accompanied by a State fisheries biologist, followed a trail consisting of dead fish, frogs, and salamanders up to a drill site operated by Marietta Royalty Co., according to the complaint filed with the West Virginia DNR. There they found a syphon hose draining the drilling waste pit into a tributary of Stillwell Creek. Acid levels at the pit measured a pH of 4.0, enough to shock and kill aquatic life, according to West Virginia District Fisheries Biologist Scott Morrison. Samples and photographs were taken by the DNR. No dead aquatic life was found above the sample

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10 West Virginia Department of Energy states that "...now the Division does not allow that type of practice, and would not let a landowner subvert the reclamation law."

11 References for case cited: Complaint form filed in circuit court of Doddridge County, West Virginia, #81-c-18. Judgment form filed in circuit court of Doddridge County, West Virginia. Water quality summary of Ray Willey farm. Letter from D. J. Horvath to Ray Willey. Water analysis done by Mountain State Environmental Service. Veterinary report on cattle and hogs of Willey farm. Lab reports from National Veterinary Services Laboratories documenting abnormalities in Willey livestock.

site. Marietta Royalty Co. was fined a total of $1,000 plus $30 in court costs.[12] (WV 20)[13]

This discharge was in direct violation of West Virginia regulations.

Illegal Disposal of Oil Field Waste in Pennsylvania

In Pennsylvania, disposing of oil and gas wastes into streams prior to 1985 violated the State's general water quality criteria, but the regulations were rarely enforced. In a study conducted by the U. S. Fish and Wildlife Service, stream degradation was found in relation to chronic discharges to streams from oil and gas operations:

> The U.S. Fish and Wildlife Service conducted a survey of several streams in Pennsylvania from 1982-85 to determine the impact on aquatic life over a period of years resulting from discharge of oil field wastes to streams. The area studied has a history of chronic discharges of wastes from oil and gas operations. The discharges were primarily of produced water from production and enhanced recovery operations. The streams studied were Miami Run, South Branch of Cole Creek, Panther Run, Foster Brook, Lewis Run, and Pithole Creek. The study noted a decline downstream from discharges in all fish populations and populations of frogs, salamanders, and crayfish. (PA 02)[14]

These discharges of produced waters are presently allowed only under the National Pollutant Discharge Elimination System (NPDES) permit system.

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12 The West Virginia Department of Energy states that "This activity has now been regulated under West Virginia's general permit for drilling fluids. Under that permit there would have been no environmental damage."

13 References for case cited: Complaint Form #6/170/83, West Virginia Department of Natural Resources, 2/25/83. West Virginia Department of Natural Resources Incident Reporting Sheet, 2/26/83. Sketches of Marietta drill site. Complaint for Summons or Warrant, 3/28/83. Summons to Appear, 3/18/83. Marietta Royalty Prosecution Report, West Virginia Department of Natural Resources. Interoffice memorandum containing spill investigation details on Marietta Royalty incident.

14 References for case cited: U.S. Fish and Wildlife, Summary of Data from Five Streams in Northwest Pennsylvania, 3/85. Background information on the streams selected for fish tissue analysis, undated but after 10/23/85. Tables 1 through 3 on point source discharge samples collected in the creeks included in this study, undated but after 10/30/84.

The long-term environmental impacts of chronic, widespread illegal disposal include loss of aquatic life in surface streams and soil salt levels above those tolerated by native vegetation. In 1985, Pennsylvania established State standards concerning this type of discharge. Discharges are now permitted under the NPDES system.

The northwestern area of Pennsylvania was officially designated as a hazardous spill area (Clean Water Act, Section 311(k)) by the U.S.EPA in 1985 because of the large number of oily waste discharges that have occurred there. Even though spills are accidental releases, and thus do not constitute wastes routinely associated with the extraction of oil and gas under the sense of the 3001 exemption, spills in this area of Pennsylvania appear to represent deliberate, routine, and continuing illegal disposal of waste oil.

Breaching of pits, opening of tank battery valves, and improper oil separation have resulted in an unusually high number of sites discharging oil directly to streams. The issue was originally brought to the attention of the State through a Federal investigation of the 500,000 acre Allegheny National Forest. That investigation discovered 500 separate spills. These discharges have affected stream quality, fish population, and other related aquatic life.

The U.S. EPA declared a four-county area (including Mckean, Warren, Venango, and Elk counties) a major spill area in the summer of 1985. The area is the oldest commercial oil-producing region in the world. Chronic low-level releases have occurred in the region since earliest production and continue to this day. EPA and other agencies (e.g., U.S. Fish and Wildlife, Pennsylvania Fish and Game, Coast Guard) were concerned that continued discharge into the area's streams has already and will in the future have major environmental impact. The area is dotted with thousands of marginal stripper wells (producing a high ratio of produced water to oil), as well as thousands of abandoned wells and pits. In the Allegheny Reservoir itself, divers spotted 20 of 81 known improperly plugged or unplugged wells, 7 of which were leaking oily high-chloride produced water into the reservoir and have since been plugged. EPA is concerned that many others are also leaking native oily produced water.

The Coast Guard (USCG) surveyed the forest for oil spills and produced water discharges, identifying those of particular danger to be cleaned immediately, by government if necessary. In the Allegheny Forest alone, USCG identified over 500 sites where oil was leaking from wells, pits, pipelines, or storage tanks. In 59 cases, oil was being discharged directly into streams; 217 sites showed evidence of past discharges and were on the verge of discharging again into the Allegheny Reservoir. Illegal disposal of oil field wastes has had a detrimental effect on the environment: "...there has been a lethal effect on trout streams and damage to timber and habitat for deer, bear and grouse." On Lewis Run, 52 discharge sites have been identified and the stream supports little aquatic life. Almost all streams in the Allegheny Forest have suppressed fish population as a "...direct result of pollution from oil and gas activity." (API notes that oil and produced water leaks into streams are prohibited by State and Federal regulations.)[15] (PA 09)[16]

These leaks are prohibited by State and Federal regulations. However, discharges are allowed, by permit, under the NPDES program.

Damage to Water Wells from Oil or Gas Well Drilling and Fracturing

In West Virginia, the minimum distance established for separating oil or gas wells from drinking water wells is 200 feet. Siting of oil or gas drill sites near domestic water wells is not uncommon.[17] West Virginia has no automatic provision requiring drillers to replace water wells lost in this way; owners must replace them at their own expense

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15 Comments in the docket by API pertain to PA 09. API states that "...litigation is currently pending with respect to this case in which questions have been raised about the factual basis for government action in this case."

16 References for case cited: U.S. Geological Survey letter from Buckwalter to Rice concerning sampling of water in northern Pennsylvania, 10/27/86. Pennsylvania Department of Environmental Resources press release on analysis of water samples, undated but after 8/83. Oil and Water: When One of the By products of High-grade Oil Production is a Low-grade Allegheny National Forest, It's Time to Take a Hard Look at Our Priorities, by Jim Morrison, Pennsylvania Wildlife, Vol. 8, No. 1. Pittsburgh Press, "Spoiling a Wilderness," 1/22/84; "Oil Leaking into Streams at 300 Sites in Northwestern Area of the State," 1985. Warren Times, "Slick Issues Underscore Oil Cleanup in National Forest," 1986.

17 According to members of the Legal Aid Society of Charleston, West Virginia, landowners have little control over where oil and gas wells are sited. Although a provision exists for hearings to be held to question the siting of an oil or gas well, this process is rarely used by private landowners for economic and other reasons.

or sue the driller. Where there is contamination of a freshwater source, State regulations presume an oil or gas drilling site is responsible if one is located within 1,000 feet of the water source.

During the fracturing process, fractures can be produced, allowing migration of native brine, fracturing fluid, and hydrocarbons from the oil or gas well to a nearby water well. When this happens, the water well can be permanently damaged and a new well must be drilled or an alternative source of drinking water found.

> In 1982, Kaiser Gas Co. drilled a gas well on the property of Mr. James Parsons. The well was fractured using a typical fracturing fluid or gel. The residual fracturing fluid migrated into Mr. Parson's water well (which was drilled to a depth of 416 feet), according to an analysis by the West Virginia Environmental Health Services Lab of well water samples taken from the property. Dark and light gelatinous material (fracturing fluid) was found, along with white fibers. (The gas well is located less than 1,000 feet from the water well.) The chief of the laboratory advised that the water well was contaminated and unfit for domestic use, and that an alternative source of domestic water had to be found. Analysis showed the water to contain high levels of fluoride, sodium, iron, and manganese. The water, according to DNR officials, had a hydrocarbon odor, indicating the presence of gas. To date Mr. Parsons has not resumed use of the well as a domestic water source. (API states that this damage resulted from a malfunction of the fracturing process. If the fractures are not limited to the producing formation, the oil and gas are lost from the reservoir and are unrecoverable.)[18] (WV 17)[19]

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18 Comments in the Docket pertain to WV 17, by David Flannery and West Virginia Department of Energy. Mr. Flannery states that "...this is an area where water problems have been known to occur independent of oil and gas operations." EPA believes that the "problems" Mr. Flannery is referring to are the natural high level of fluoride, alkalinity, sodium, and total dissolved solids in the water. However, the constituents of concern found in this water well were the gelatinous material associated with the fracturing process, and hydrocarbons. West Virginia Department of Energy states that the WVDOE "...had no knowledge that the Pittsburg sand was a fresh water source." Also, WVDOE pointed out that WV Code 22B-1-20 "...requires an operator to cement a string of casing 30 feet below all fresh water zones." According to case study records, Kaiser Gas Co. did install a cement string of casing 30 feet below the Pittsburg sand, from which Mr. Parson drew his water.

19 References for case cited: Three lab reports containing analysis of water well. Letter from J. E. Rosencrance, Environmental Health Services Lab, to P. R. Merritt, Sanitarian, Jackson County, West Virginia. Letter from P. R. Merritt to J. E. Rosencrance requesting analysis. Letter from M. W. Lewis, Office of Oil and Gas, to James Parsons stating State cannot help in recovering expenses, and Mr. Parsons must file civil suit to recover damages. Water well inspection report - complaint. Sample report forms.

There were no violations of West Virginia regulations in this case.

Damage cases involving drilling activity in proximity to residential areas are known to have occurred in Pennsylvania:

Civil suit was brought by 14 families living in the village of Belmar against a Meadville-based oil drilling company, Norwesco Development Corporation, in June 1986. Norwesco had drilled more than 200 wells near Belmar, and residents of the village claimed that the activity had contaminated the ground water from which they drew their domestic water supply. The Pennsylvania Department of Environmental Resources and the Pennsylvania Fish Commission cited Norwesco at least 19 times for violations of State regulations. Norwesco claimed it was not responsible for contamination of the ground water used by the village of Belmar. Norwesco suggested instead that the contamination was from old, long-abandoned wells. The Pennsylvania Department of Environmental Resources (DER) agreed with Belmar residents that the contamination was from the current drilling operations. Ground water in Belmar had been pristine prior to the drilling operation of Norwesco. All families relying on the ground water lost their domestic water supply. The water from the contaminated wells would "...burn your eyes in the shower, and your skin is so dry and itchy when you get out." Families had to buy bottled water for drinking and had to drive, in some cases, as far as 30 miles to bathe. Not only were residents not able to drink or bathe using the ground water; they could not use the water for washing clothes or household items without causing permanent stains. Plumbing fixtures were pitted by the high level of total dissolved solids and high chloride levels.

In early 1986, DER ordered Norwesco to provide Belmar with an alternative water supply that was equal in quality and quantity to what the Belmar residents lost when their wells were contaminated. In November 1986 Norwesco offered a cash settlement of $275,000 to construct a new water system for the village and provided a temporary water supply. (PA 08)[20]

This case represents a violation of Pennsylvania regulations.

Problems with Landspreading in West Virginia

Landspreading of drilling muds containing up to 25,000 ppm chlorides was allowed in West Virginia until November 1, 1987. The new limit is 12,500 ppm chlorides. These concentrations of chlorides are considerably

20 References for case cited: Pittsburgh Press, "Franklin County Village Sees Hope after Bad Water Ordeal," 12/7/86. Morning News, "Oil Drilling Firm Must Supply Water to Homes," 1/7/86; "Village Residents Sue Drilling Company," 6/7/86.

higher than concentrations permitted for landspreading in other States and are several times higher than native vegetation can tolerate. Landspreading of these high-chloride muds may result in damage to arable land. This waste drilling mud may kill surface vegetation where the mud is directly applied; salts in the wastes can leach into surrounding soil, affecting larger plants and trees. Leaching of chlorides into shallow ground water is also a potential problem associated with this practice.

In early 1986 Tower Drilling land-applied the contents of a reserve pit to an area 100 feet by 150 feet. All vegetation died in the area where pit contents were directly applied, and three trees adjacent to the land application area were dying allegedly because of the leaching of high levels of chlorides into the soil. A complaint was made by a private citizen to the West Virginia DNR. Samples taken by West Virginia DNR of the contaminated soil measured 18,000 ppm chlorides.[21] (WV 13)[22]

Land applying reserve pit contents with more than 12,500 ppm chlorides is now in violation of West Virginia regulations.

Problems with Enhanced Oil Recovery (EOR) and Abandoned Wells in Kentucky

The Martha Oil Field, located in northeastern Kentucky, is situated on the border of Lawrence and Johnson counties and occupies an area in excess of 50 square miles. Oil production began in the early 1920s and secondary recovery operations or waterflooding commenced in 1955. Ashland Exploration, Inc., operated UIC-permitted injection wells in the area. Approximately 8,500 barrels of fresh water were being injected per day at an average pressure of 700 pounds per square inch.

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21 Comments in the Docket by David Flannery and API pertain to WV 13. The statements by API and Mr. Flannery are identical. They state that it might not be "...possible to determine whether it was the chloride concentration alone which caused the vegetation stress." Also, they claim that the damage was short term and "...full recovery of vegetation was made." Neither commenter submitted supporting documentation.

22 References for case cited: West Virginia Department of Natural Resources complaint form #6/131/86. Analytical report on soil analysis of kill area.

Several field investigations were conducted by the U.S. Environmental Protection Agency, Region IV, to appraise the potential for and extent of contamination of ground-water resources. Field inspections revealed widespread contamination of underground sources of drinking water (USDWs).

From April 29 through May 8, 1986, representatives of the U.S. EPA, Region IV, conducted a surface water investigation in the Blaine Creek watershed near Martha, Kentucky. The study was requested by the U.S. EPA Water Management Division to provide additional baseline information on stream water quality conditions in the Blaine Creek area. Blaine Creek and its tributaries have been severely impacted by oil production activities conducted in the Martha field since the early 1900s. The Water Management Division issued an administrative order requiring that waterflooding of the oil-bearing strata cease by February 4, 1986, and also requiring that direct or indirect brine discharges to area streams cease by May 7, 1986.

For the study in 1986, 27 water chemistry sampling stations, 13 of which were also biological sampling stations, were established in the Blaine Creek watershed. Five streams in the study area were considered control stations. Biological sampling indicated that macroinvertebrates in the immediate Martha oil field area were severely impacted. Many species were reduced or absent at all stations within the oil field. Blaine Creek stations downstream of the oil field, although impacted, showed gradual improvement in the benthic macroinvertebrates. Control stations exhibited the greatest diversity of benthic macroinvertebrate species. Water chemistry results for chlorides generally indicated elevated levels in the Martha oil field drainage area. Chloride values in the affected area of the oil field ranged from 440 to 5,900 mg/L. Control station chloride values ranged from 3 to 42 mg/L.

In May of 1987, EPA, Region IV, conducted another surface water investigation of the Blaine Creek watershed. The study was designed to document changes in water quality in the watershed 1 year following the cessation of oil production activities in the Martha oil field. By May of 1987, the major operator in the area, Ashland Exploration, Inc., had ceased operations. Some independently owned production wells were still in service at this time. Chloride levels, conductivity, and total dissolved solids levels had significantly decreased at study stations within the Martha oil field. Marked improvements were observed in the benthic invertebrate community structures at stations within the Martha field. New species that are considered sensitive to water quality conditions were present in 1987 at most of the biological sampling stations, indicating that significant water quality improvements had occurred following cessation of oil production activities in the Martha field. Chloride levels in one stream in the Blaine Creek watershed decreased from 5,900 mg/L to 150 mg/L.[23]

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[23] References for case cited: Martha Oil Field Water Quality Study, Martha, Kentucky, U.S. EPA, Athens, Georgia, May 1986. Martha Oil Field Water Quality Study, Martha, Kentucky, U.S. EPA, Athens, Georgia, May 1987.

In response to EPA's notice of violations and other requirements, Ashland proposed to EPA that it would properly plug and abandon all existing injection wells, oil production wells, and water-supply wells and most gas production wells in the Martha field. EPA, Region IV, issued to Ashland an Order on Consent With Administrative Civil Penalty under the authority of Section 1423(9)(2) of the SDWA. Ashland has paid an administrative penalty of $125,000 and will plug and abandon approximately 1,433 wells in compliance with EPA standards. If warranted, Ashland will provide alternative water supplies to private water well users whose supplies have been adversely affected by oil production activities.

SOUTHEAST

The Southeast zone includes North Carolina, South Carolina, and Georgia. There is little oil and gas activity in this zone. No field research was conducted to collect damage cases in this zone.

GULF

The Gulf zone includes Arkansas, Louisiana, Mississippi, Alabama, and Florida. Attention in the damage case effort was focused on Arkansas and Louisiana, the two major producers of the zone.

Operations

Operations in Arkansas are predominantly small to mid-sized operations in mature production areas. A significant percentage of

production in this area comes from stripper wells, which produce large volumes of associated produced water containing high levels of chlorides. For Arkansas, most production occurs in the southern portion of the State.

The average depth of a new well drilled in Arkansas in 1985 was 4,148 feet. That year 121 exploratory wells were drilled and 1,055 new wells were completed.

Louisiana has two distinct production areas. The northern half of the State is dominated by marginal stripper production from shallow wells in mature fields. The southern half of Louisiana has experienced most of the State's development activity in the last decade. There has been heavy, capital-intensive development of the Gulf Coast area, where gas is the principal product. Wells tend to be of medium depth; operations are typically located in or near coastal wetland areas on barge platforms or small coastal islands. Operators dredge canals and estuaries to gain access to sites.

In this area, reserve pits are constructed out of the materials found on coastal islands, mainly from peat, which is highly permeable and susceptible to damage after exposure to reserve pit fluids. Reserve pits on barges are self-contained, but are allowed to be discharged in particular areas if levels of certain constituents in wastes are below specified limits. If certain constituents are found in concentrations above these limits in the waste, they must be injected or stored in pits (unlined) on coastal islands.

For many operators in the Gulf Coast area, produced water is discharged directly to adjacent water bodies. Fields in this region have an average water/oil ratio of from 4:1 to 6:1. The Louisiana Department of Environmental Quality (DEQ) is now requiring that operators apply for permits for these discharges. At this writing, the Louisiana DEQ had received permit applications for approximately 750 to 800 discharge points. Results of field work done by the Louisiana DEQ, the Louisiana Geological Survey, and the Louisiana University Marine Consortium show that roughly 1.8 to 2.0 million barrels of produced water are discharged daily in this area. According to the Louisiana Geological Survey, many receiving water bodies contain fresh water, with some receiving water bodies 70 times fresher than the oil field discharges. The U.S. Fish and Wildlife Service has stated that it will aggressively oppose any permits for produced water discharges in the Louisiana wetlands of the Gulf Coast.

The average depth of a new well drilled in northern Louisiana in 1985 was 2,713 feet; along the Gulf Coast it was 10,150 feet. In the northern part of the State, 244 exploratory wells were drilled and 4,033 production wells were completed. In the southern part of the State, 215 exploratory wells were drilled and 1,414 production wells were completed.

Types of Operators

In Arkansas, operators are generally small to mid-sized independents, including some established operators and others new to the industry. Because production comes mostly from stripper wells, operators tend to be vulnerable to market fluctuations.

Northern Louisiana's operators, like those in Arkansas, tend to be small to mid-sized independents. They share the same economic vulnerabilities with their neighbors in Arkansas. In addition, however,

Louisiana's more marginal operations may be particularly stressed by the new Rule 29B, which requires the closing out and elimination of all current and future onsite produced water disposal pits by 1989. Estimated closing costs per pit are $20,000.

Operators in southern Louisiana tend to be major companies and large independents. They are less susceptible to fluctuating market conditions in the short term. Projects in the south tend to be larger than those in the north and are located in more environmentally sensitive areas.

Major Issues

Ground-Water Contamination from Unlined Produced Water Disposal Pits and Reserve Pits

Unlined produced water disposal pits have been used in Louisiana for many years and are only now being phased out under Rule 29B. Past practice has, however, resulted in damages to ground water and danger to human health.

> In 1982, suit was brought on behalf of Dudley Romero et al. against operators of an oil waste commercial disposal facility, PAB Oil Co. The plaintiffs stated that their domestic water wells were contaminated by wastes dumped into open pits in the PAB Oil Co. facility which were alleged to have migrated into the ground water, rendering the water wells unusable. Oil field wastes are dumped into the waste pits for skimming and separation of oil. The pits are unlined. The PAB facility was operating prior to Louisiana's first commercial oil field waste facility regulations. After promulgation of new regulations, the facility continued to operate for 2 years in violation of the new regulations, after which time the State shut down the facility.
>
> The plaintiff's water wells are downgradient of the facility, drilled to depths of 300 to 500 feet. Problems with water wells date from 1979. Extensive analysis was performed by Soil Testing Engineers, Inc., and U.S. EPA, on the plaintiff's water wells adjacent to the site to determine the probability of the well contamination coming from the PAB Oil Co. site. There was also analysis on surface soil contamination. Soil Testing

Engineers, Inc., determined that it was possible for the wastes in the PAB Oil Co. pits to reach and contaminate the Romeros' water wells. Surface sampling around the perimeter of the PAB Oil Co. site found high concentrations of metals. Resistivity testing showed that plumes of chloride contamination in the water table lead from the pits to the water wells. Borings that determined the substrata makeup suggested that it would be possible for wastes to contaminate the Romero ground water within the time that the facility had been in operation if the integrity of the clay cap in the pit had been lost (as by deep excavation somewhere within it). The pit was 12 feet deep and within range to percolate into the water-bearing sandy soil.

The plaintiffs complained of sickness, nausea, and dizziness, and a loss of cattle. The case was settled out of court. The plaintiffs received $140,000 from PAB Oil Co. (LA 67)[24]

Unlined commercial disposal pits are now illegal in Louisiana.

The ground in this area is highly permeable, allowing pit contents to leach into soil and ground water. Waste constituents potentially leaching into ground water from unlined pits include arsenic, cadmium, chromium, copper, lead, nickel, zinc, and chlorides. There have been incidents illustrating the permeability of subsurface formations in this area.[25]

Allowable Discharge of Drilling Mud into Gulf Coast Estuaries

Under existing Louisiana regulations, drilling muds from onshore operations may be discharged into estuaries of the Gulf of Mexico. The State issues permits for this practice on a case-by-case basis. These

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24 References for case cited: Soil Testing Engineers, Inc., Brine Study, Romero, et al., Abbeville, Louisiana, 10/19/82. U.S. EPA lab analysis of pits and wells, 10/22/81. Dateline, Louisiana: Fighting Chemical Dumping, by Jason Berry, May-June, 1983.

25 A gas well operated by Conoco, which had been plugged and abandoned, blew out below the surface from December 11, 1985, to January 9, 1986. The blowout sent gas through fault zones and permeable formations to the land surface owned by Claude H. Gooch. The gas could be ignited by a match held to the ground. The gas was also determined to be a potential hazard to drinking water wells in the immediate area.

estuaries are often valuable commercial fishing grounds. Since the muds can contain high levels of toxic metals, the possibility of bioaccumulation of these metals in shellfish or finfish is of concern to EPA.

> In 1984, the Glendale Drilling Co., under contract to Woods Petroleum, was drilling from a barge at the intersection of Taylor's Bayou and Cross Bayou. The operation was discharging drill cuttings and mud into the bayou within 1,300 feet of an active oyster harvesting area and State oyster seeding area. At the time of discharge, oyster harvests were in progress. (It is State policy in Louisiana not to grant permits for the discharge of drill cuttings within 1,300 feet of an active oyster harvesting area. The Louisiana Department of Environmental Quality does not allow discharge of whole mud into estuaries.)
>
> A State Water Pollution Control Division inspector noted that there were two separate discharges occurring from the barge and a low mound of mud was protruding from the surface of the water beneath one of the discharges. Woods Petroleum had a letter from the Louisiana Department of Environmental Quality authorizing them to discharge the drill cuttings and associated mud, but this permit would presumably not have been issued if it had been known that the drilling would occur near an oyster harvesting area. While no damage was noted at time of inspection, there was great concern expressed by the Louisiana Oyster Growers Association, the Louisiana Department of Wildlife and Fisheries, Seafood Division, and some parts of the Department of Water Pollution Control Division of the Department of Environmental Quality. The concern of these groups stemmed from the possibility that the discharge of muds and cuttings with high content of metals may have long-term impact on the adjacent commercial oyster fields and the State oyster seed fields in nearby Junop Bay. In such a situation, metals can precipitate from the discharge, settling in progressively higher concentrations in the bayou sediments where the oysters mature. The bioaccumulation of these metals by the oysters can have an adverse impact on the oyster population and could also lead to human health problems if contaminated oysters are consumed.
>
> The Department of Environmental Quality decided in this case to direct the oil company to stop the discharge of drill cuttings and muds into the bayou. In this instance, the Department of Environmental Quality ordered that a drill cutting barge be used to contain the remainder of the drill cuttings. The company was not ordered to clean up the mound of drill cuttings that it had already deposited in the bayou. (LA 20)[26]

Activities in this case, though allowed by the State, are illegal according to State law.

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26 References for case cited: Louisiana Department of Environmental Quality, Water Pollution Control Division, Office of Water Resources, internal memorandum, 6/3/85.

Illegal Disposal of Oil Field Waste in the Louisiana Gulf Coast Area

The majority of damage cases collected in Louisiana involve illegal disposal or inadequate facilities for containment of wastes generated by operations on the Gulf Coast. For example:

> Two Louisiana Water Pollution Control inspectors surveyed a swamp adjacent to a KEDCO Oil Co. facility to assess flora damage recorded on a Notice of Violation issued to KEDCO on 3/13/81. The Notice of Violation discussed produced water discharges into an adjacent canal that emptied into a cypress swamp from a pipe protruding from the pit levee. Analysis of a sample collected by a Mr. Martin, the complainant, who expressed concern over the high-chloride produced water discharge into the canal he used to obtain water for his crawfish pond, showed salinity levels of 32,000 ppm (seawater is 35,000 ppm).
>
> On April 15, 1981, the Water Pollution Control inspectors made an effort to measure the extent of damage to the trees in the cypress swamp. After surveying the size of the swamp, they randomly selected a compass bearing and surveyed a transect measuring 200 feet by 20 feet through the swamp. They counted and then classified all trees in the area according to the degree of damage they had sustained. Inspectors found that "...an approximate total area of 4,088 acres of swamp was severely damaged." Within the randomly selected transect, they classified all trees according to the degree of damage. Out of a total of 105 trees, 73 percent were dead, 18 percent were stressed, and 9 percent were normal. The inspectors' report noted that although the transect ran through a heavily damaged area, there were other areas much more severely impacted. They therefore concluded, based upon data collected and firsthand observation, that the percentages of damaged trees recorded "...are a representative, if not conservative, estimate of damage over the entire affected area." In the opinion of the inspectors, the discharge of produced water had been occurring for some time, judging by the amount of damage sustained by the trees. KEDCO was fined $9,500 by the State of Louisiana and paid $4,500 in damages to the owner of the affected crawfish farm. (LA 45)[27]

This discharge was in violation of Louisiana regulations.

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27 References for case cited: Louisiana Department of Natural Resources, Water Pollution Control Division, internal memo, Cormier and St. Pe to Givens, concerning damage evaluation of swamp near the KEDCO Oil Co. facility 6/24/81. Notice of Violation, Water Pollution Control Log #2-8-81-21.

Most of the damage cases collected involved small operations run by independent companies. Some incidents, however, involved major oil companies:

Sun Oil Co. operates a site located in the Chacahoula Field. A Department of Natural Resources inspector noted a site configuration during an inspection (6/25/82) of a tank battery surrounded by a pit levee and a pit (30 yards by 50 yards). The pit was discharging produced water into the adjacent swamp in two places, over a low part in the levee and from a pipe that had been put through the ring levee draining directly into the swamp. Produced water, oil, and grease were being discharged into the swamp. Chloride concentrations from samples taken by the inspectors ranged from 2,948 to 4,848 ppm, and oil and grease concentrations measured 12.6 to 26.7 ppm. The inspector noted that the discharge into the swamp was the means by which the company drains the tank battery ring levee area. A notice of violation was issued to Sun Oil by the Department of Natural Resources. (LA 15)[28]

This discharge was in violation of Louisiana regulations.

Some documented cases noted damage to agricultural crops:

Dr. Wilma Subra documented damage to D.T. Caffery's sugar cane fields adjacent to a production site, which included a saltwater disposal well, in St. Mary Parish. The operator was Sun Oil. The documentation was collected between July of 1985 and November of 1986 and included reports of salt concentrations in soil at various locations in the sugar cane fields, along with descriptions of accompanying damage. Dr. Subra noted that the sugar cane fields had various areas that were barren and contained what appeared to be sludge. The production facility is upgradient from the sugar cane fields, and Dr. Subra surmised that produced water was discharged onto the soil surface from the facility and that a plume of salt contamination spread downgradient, thereby affecting 7.3 acres of sugar cane fields, over a period of a year and a half.

In July 1985, Dr. Subra noted that the cane field, though in bad condition, was predominantly covered with sugar cane. There were, however, weeds or barren soil covering a portion of the site. The patch of weeds and barren soil matched the area of highest salt concentration. In the area where the topography suggested that brine concentrations would be lowest, the sugar cane appeared healthy. Subsequent field investigation and soil sampling conducted by Dr. Subra in November of 1986 found the field to be nearly barren, with practically no sugar cane growing.

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28 References for case cited: Louisiana Department of Natural Resources, Water Pollution Control Division, internal memo from Cormier to Givens, 8/16/82, concerning Sun Oil Co. brine discharge, Chacahoula Field. Log #2-8-81-122. Lab analysis, 7/2/82.

Dr. Subra measured concentrations of salts in the soil ranging from a low of 1,403 ppm to 35,265 ppm at the edge of the field adjacent to the oil operation. Sun has undertaken a reclamation project to restore the land. It is estimated that the project will take 2 to 3 years to complete. In the interim, Sun Oil Co. will pay the sugar cane farmer for loss of crops.[29] (LA 63)[30]

The State of Louisiana has not taken any enforcement action in this case; it is unclear whether any State regulations were violated.

Most damage associated with illegal disposal involves disposal of produced water containing high levels of chloride (brine). Illegal disposal of other types of oil field waste also result in environmental damage:

Chevco-Kengo Services, Inc. operates a centralized disposal facility near Abbeville, Louisiana. Produced water and other wastes are transported from surrounding production fields by vacuum truck to the facility. Complaints were filed by private citizens alleging that discharges from the facility were damaging crops of rice and crawfish, and that the facility represented a threat to the health of nearby residents. An inspection of the site by the Water Pollution Control Division of the Department of Natural Resources found that a truck washout pit was emptying oil field wastes into a roadside ditch flowing into nearby coulees.

Civil suit was brought by private citizens against Chevco-Kengo Services, Inc., asking for a total of $4 million in property damages, past and future crop loss, and exemplary damages. Lab analysis performed by the Department of Natural Resources of waste samples indicated high metals content of the wastes, especially in samples taken from the area near the facility and in the adjacent rice fields, indicating that the discharge of wastes from the facility was the source of damage to the surrounding land. The case is in litigation.[31] (LA90)[32]

The State did not issue a notice of violation in this case. However, this type of discharge is illegal.

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29 API states that an accidental release occurred in this case. EPA records show this release lasted 2 years.

30 References for case cited: Documentation from Dr. Wilma Subra, including a series of maps documenting changes in the sugar cane over a period of time, 12/86. Maps showing location of sampling and salt concentrations.

31 API states that these discharges were accidental.

32 References for case cited: Louisiana Department of Natural Resources, Water Pollution Control Division, internal memo, lab analysis, and photographs, 8/25/83. Letter from Westland Oil Development Corp. to Louisiana Department of Natural Resources, 4/15/83.

Illegal Disposal of Oil Field Waste in Arkansas

The majority of damage cases found in Arkansas relate to illegal dumping of produced water and oily waste from production units. Damages typically include pollution of surface streams and contamination of soil with high levels of chlorides and oil, documented or potential contamination of ground water with elevated levels of chlorides, and damage to vegetation (especially forest and timberland), from exposure to high levels of chlorides.

An oil production unit operated by Mr. J. C. Langley was discharging oil and produced water in large quantities onto the property of Mr. Melvin Dunn and Mr. W. C. Shaw. The oil and produced water discharge allegedly caused severe damage to the property, interfered with livestock on the property, and delayed construction of a planned lake. Mr. Dunn had spoken repeatedly with a company representative operating the facility concerning the oil and produced water discharge, but no changes occurred in the operation of the facility. A complaint was made to Arkansas Department of Pollution Control and Ecology (ADPCE), the operator was informed of the situation, and the facility was brought into compliance. Mr. Dunn then hired a private attorney in order that remedial action be taken. It is not known whether the operator cleaned up the damaged property.[33] (AR 07)[34]

This discharge was in violation of Arkansas regulations.

On September 20, 1984, an anonymous complaint was filed with ADPCE concerning the discharge of oil and produced water in and near Smackover Creek from production units operated by J. S. Beebe Oil Account. Upon investigation by ADPCE, it was found that saltwater was leaking from a salt water disposal well located on the site. Mr. Beebe wrote a letter stating his willingness to correct the situation. On November 16, 1984, the site was again investigated by ADPCE, and it was found that pits on location were being used as the primary disposal facility and were

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33 API states that this incident constituted a spill and is therefore a non-RCRA issue.

34 References for case cited: Arkansas Department of Pollution Control and Ecology (ADPCE) Complaint form, #EL 1721, 5/14/84. Letter from Michael Landers, attorney to Mr. Dunn, requesting investigation from Wayne Thomas concerning Langley violations. Letter from J. C. Langley to Wayne Thomas, ADPCE, denying responsibility for damages of Dunn and Shaw property, 6/5/84. Certified letter from Wayne Thomas to J. C. Langley discussing violations of facility and required remedial actions, 5/30/87. Map of violation area, 5/29/84. ADPCE oil field waste survey documenting unreported oil spill on Langley unit, 5/25/84. Letter from Michael Landers, attorney to ADPCE, discussing damage to property of Dunn and Shaw, 5/11/84.

overflowing and leaking into Smackover Creek. The ADPCE issued a Notice of Violation (LIS 84-066) and noted that the pits were below the creek level and overflowed into the creek when heavy rains occurred. One pit was being siphoned over the pit wall, while waste from another pit was flowing onto the ground through an open pipe. The floors and walls of the pits were saturated, allowing seepage of waste from the pits. ADPCE ordered Mr. Beebe to shut down production and clean up the site and fined him $10,500. (AR 10)[35]

These discharges were occurring in violation of Arkansas regulations.

The State of Arkansas has limited resources for inspecting disposal facilities associated with oil and gas production. (See Table VII-7.) Furthermore, the two State agencies responsible for regulating oil and gas operations (the Arkansas Oil and Gas Commission (OGC) and the Arkansas Department of Pollution Control and Ecology (ADPCE)) have overlapping jurisdictions. In the next case, the landowner is the Arkansas Game and Fish Commission, which attempted to enforce a permit it issued to the operator for drilling activity on the Commission's land. As of summer 1987, no permit had been issued by either the OGC or the ADPCE.

In 1983 and again in 1985, James M. Roberson, an oil and gas operator, was given surface access by the Arkansas Game and Fish Commission for drilling in areas in the Sulphur River Wildlife Management Area (SRWMA), but was not issued a drilling permit by either of the State agencies that share jurisdiction over oil and gas operations. Surface rights are owned by the Arkansas Game and Fish Commission. The Commission attempted to write its own permits for this operation to protect the wildlife management area resources. Mr. Roberson repeatedly violated the requirements contained in these surface use permits, and the Commission also determined that he was in violation of general State and Federal regulations applicable to his operation in the absence of OGC or ADPCE permits. These violations led to release of oil and high-chloride produced water into the wetland areas of the Sulphur River and Mercer Bayou from a leaking saltwater disposal well and illegal produced water disposal pits maintained by the operator.

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35 References for case cited: ADPCE complaint form #EL 1792, 9/20/84, and 8/23/84. ADPCE inspection report, 9/5/84. Letter from ADPCE to J. S. Beebe outlining first run of violations, 9/6/84. Letter stating willingness to cooperate from Beebe to ADPCE, 9/14/84. ADPCE complaint form #EL 1789, 9/19/84. ADPCE inspection report, 9/25 and 9/26/84. ADPCE complaint form #EL 1822, 11/16/84. ADPCE Notice of Violation, Findings of Fact, Proposed Order and Civil Penalty Assessment, 11/21/84. Map of area. Miscellaneous letters.

Oil and saltwater damage to the area was documented in a study conducted by Hugh A. Johnson, Ph.D., a professor of biology at Southern Arkansas University. His study mapped chloride levels around each well site and calculated the affected area. The highest chloride level recorded in the wetland was 9,000 ppm (native vegetation begins to be stressed from exposure to 250 ppm chlorides). He found that significant areas around each well site had dead or stressed vegetation related to excessive chloride exposure. The Game and Fish Commission fears that continued discharges of produced water and oil in this area will threaten the last remaining forest land in the Red River bottoms.[36] (AR 04)[37]

These discharges were in violation of State and Federal regulations.

Jurisdiction in the above case is unclear. Under a 1981 amendment to the State Oil and Gas Act, OGC was granted formal permit authority over oil and gas operations, but this authority is to be shared in certain situations with the ADPCE. Jurisdiction is to be shared where Underground Injection Control (UIC) wells are concerned, but is not clearly defined with respect to construction or management of reserve pits or disposal of drilling wastes. ADPCE has made attempts to clarify the situation by issuing informal letters of authorization to operators, but these are not universally recognized throughout the State. (A full discussion of this issue can be found in Chapter VII and in Appendix A.)

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[36] API states that the Arkansas Water and Air Pollution Act gives authority at several levels to require cleanup of these illegal activities and to prevent further occurrences. EPA believes that even though State and Federal Laws exist which prohibit this type of activity, no mechanism for enforcement is in place.

[37] References for case cited: Letter from Steve Forsythe, Department of the Interior (DOI), to Pat Stevens, Army Corps of Engineers (ACE), stating that activities of Mr. Roberson have resulted in significant adverse environmental impacts and disruptions and that DOI recommends remedial action be taken. Chloride Analysis of Soil and Water Samples of Selected Sites in Miller County, Arkansas, by Hugh A. Johnson, Ph.D., 10/22/85. Letter to Pat Stevens, ACE, from Dick Whittington, EPA, discussing damages caused by Jimmy Roberson in Sulphur River Wildlife Management Area (SRWMA) and recommending remedial action and denial of new permit application. Oil and Gas well drilling permits dated 1983 and 1985 for Roberson activities. A number of letters and complaints addressing problems in SRWMA resulting from activities of James Roberson. Photographs. Maps.

Improperly Operated Injection Wells

Improper operation of injection wells raises the potential for long-term damage to ground-water supplies, as the following case from Arkansas illustrates.

> On September 19, 1984, Mr. James Tribble made a complaint to the Arkansas Department of Pollution Control and Ecology concerning salt water that was coming up out of the ground in his yard, killing his grass and threatening his water well. There are many oil wells in the area, and water flooding is a common enhanced recovery method at these sites. Upon inspection of the wells nearest to his residence, it was discovered that the operator, J. C. McLain, was injecting salt water into an unpermitted well. The salt water was being injected into the casing, or annulus, not into tubing. Injection into the unsound casing allegedly allowed migration into the freshwater zone. A produced water pit at the same site was near overflowing. State inspectors later noted in a followup inspection that the violations had been corrected. No fine was levied. (AR 12) [38]

Operation of this well would now be in violation of UIC requirements.

MIDWEST

The Midwest zone includes the States of Michigan, Iowa, Indiana, Wisconsin, Illinois, and Missouri. Damage cases were collected in Michigan.

Operations

Michigan produces both oil and gas from limestone reef formations at sites scattered throughout the State at a depth of 4,000 to 6,000 feet.

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38 References for case cited: ADPCE Complaint form, #EL 1790, 9/19/84. ADPCE inspection report, 9/20/84. Letter from ADPCE to Mr. J. C. McLain describing violations and required corrective action, 9/21/84. ADPCE reinspection report, 10/11/84.

Oil and gas development is relatively new in this area, and most production is primary (that is, as yet it involves no enhanced or secondary recovery methods, such as water flooding). Exploration in Michigan is possibly the most intense currently under way anywhere in the country. The average depth of new wells drilled in 1985 was 4,799 feet. In that year 863 wells were completed, of which 441 were exploration wells.

Types of Operators

Operators in Michigan include everything from small independent companies to the major oil companies.

Major Issues

Ground-Water Contamination in Michigan

All the damage cases gathered in Michigan are based on case studies written by the Michigan Geological Survey, which regulates oil and gas operations in the State. All of these cases deal with ground water contamination with chlorides. While the State has documented that damages have occurred in all cases, sources of damages are not always evident. Usually, several potential sources of contamination are listed for each case, and the plume of contamination is defined by using monitoring wells. Most of the cases involve disposal of produced waters.

> In June 1983, a water well owned by Mrs. Geneva Brown was tested after she had filed a complaint to the Michigan Geological Survey. After responding, the Michigan Geological Survey found a chloride concentration of 490 ppm in the water. Subsequent sampling from the water well of a neighbor, Mrs. Dodder, showed that her well measured 760 ppm chloride in August. There are a total of 15 oil and gas wells in the area surrounding the contaminated water wells. Only five of the wells are still producing, recovering a combination of oil and produced water. The source of the pollution was evidently the H. E. Trope, Inc., crude oil separating facilities and brine storage tanks located upgradient from the contaminated water wells. Monitoring wells were installed to confirm the source of the contamination. Stiff diagrams were used to confirm the similarity of the constituents of the formation brine and the chloride contamination of the

affected water wells. Sample results located two plumes of chloride contamination ranging in concentration from 550 to 1,800 ppm that are traveling in a southeasterly direction downgradient from the produced water storage tanks and crude oil separator facilities owned by H.E. Trope. (MI 05)[39]

Produced water spills from production facilities are covered by Michigan regulations.

Ground-water contamination in the State has also been caused by injection wells, as illustrated by the following case:

> In April 1980, residents of Green Ridge Subdivision, located in Section 15, Laketon Township, Muskegon County, complained of bad-tasting water from their domestic water wells. Some wells sampled by the local health department revealed elevated chloride concentrations. Because of the proximity of the Laketon Oil Field, an investigation was started by the Michigan Geological Survey. The Laketon Oil Field consists of dry holes, producing oil wells, and a produced water disposal well, the Harris Oil Corp. Lappo #1. Oil wells produce a mixture of oil and produced water. The produced water is separated and disposed of by gravity in the produced water disposal well and is then placed back in the producing formation. After reviewing monitoring well and electrical resistivity survey data, the Michigan Geological Survey concluded that the source of the contamination was the Harris Oil Corp. Lappo #1 produced water disposal well, which was being operated in violation of UIC regulations. (MI 06)[40]

This disposal well was being operated in violation of State regulations.

Damage to ground water under a drill site can occur even where operators take special precautions for drilling near residential areas. An example follows:

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39 References for case cited: Open file report, Michigan Department of Natural Resources, Investigation of Salt-Contaminated Groundwater in Cat Creek Oil Field, Hersey Township, conducted by D. W. Forstat, 1984. Appendix includes correspondence relating to investigation, area water well drilling logs, Stiff diagrams and water analysis, site monitor well drilling logs, and water sample analysis for samples used in the investigation.

40 References for case cited: Open file report, Michigan Department of Natural Resources, Investigation of Salt-Contaminated Groundwater in Green Ridge Subdivision, Laketon Township, conducted by B. P. Shirey, 1980. Appendix includes correspondence relating to investigation, area water well drilling logs, Stiff diagrams and water analysis, site monitor well drilling logs, and water sample analysis for samples used in the investigation.

Drilling operations at the Burke Unit #1 caused the temporary chloride contamination of two domestic water wells and longer lasting chloride contamination of a third well closer to the drill site. The operation was carried out in accordance with State regulations and special site restrictions required for urban areas, using rig engines equipped with mufflers, steel mud tanks for containment of drilling wastes, lining for earthen pits that may contain salt water, and the placement of a conductor casing to a depth of 120 feet to isolate the well from the freshwater zone beneath the rig.

The drilling location is underlain by permeable surface sand, with bedrock at a depth of less than 50 feet. Contamination of the ground water may have occurred when material flushed from the mud tanks remained in the lined pit for 13 days before removal. (The material contained high levels of chlorides, and liners can leak.) According to the State report, this would have allowed for sufficient time for contaminants to migrate into the freshwater aquifer. A leak from the produced water storage tank was also reported by the operator to have occurred before the contamination was detected in the water wells. One shallow well was less than 100 feet directly east of the drill pit area and 100 to 150 feet southeast of the produced water leak site. Chloride concentrations in this well measured by the Michigan Geological Survey were found to range from 750 (9/5/75) to 1,325 (5/23/75) ppm. By late August, two of the wells had returned to normal, while the third well still measured 28 times its original background concentration of chloride. (MI 04)[41]

In this case, damages resulted from practices that are not in violation of State regulations.

PLAINS

The Plains zone includes North Dakota, South Dakota, Nebraska, and Kansas. All of these States have oil and gas production, but for this study, Kansas was the only State visited for damage case collection. Discussion is limited to that State.

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41 References for case cited: Open file report, Michigan Department of Natural Resources, Report on Ground-Water Contamination, Sullivan and Company, J.D. Burke No. 1, Pennfield Township, conducted by J. R. Byerlay, 1976. Appendix includes correspondence relating to investigation, area water well drilling logs, Stiff diagrams and water analysis, site monitor well drilling logs, and water sample analysis for samples used in the investigation.

Operations

Oil and gas production in Kansas encompasses a wide geographical area and ranges from marginal oil production in the central and eastern portions of the State to significant gas production in the western portion of the State. Kansas is the home of one of the largest gas fields in the world, the Giant Hugoton field. Other major areas of oil production in Kansas include the Central Kansas Uplift area, better known as the "Kansas Oil Patch," the El Dorado Field in the east and south, and the Eastern Kansas Shoestring sandstone area. The Eastern Kansas Shoestring sandstone production area is composed mainly of marginal stripper operations. The overall ratio of produced water to oil in Kansas is about 40:1, but the ratio varies depending on economic conditions, which may force the higher water-to-oil ratio wells (i.e., those in the Mississippian and Arbuckle producing formations) to shut down.

The average depth of a new well drilled in Kansas in 1985 was 3,770 feet. In that year 6,025 new wells were completed. Of those, 1,694 were exploratory.

Types of Operators

Operators in Kansas include the full range from majors to small independents. The Hugoton area is dominated by majors and mid-sized to large independents. Spotty oil production in the northern half of eastern Kansas is dominated by small independent producers, and oil production is densely developed in the southern half.

Major Issues

Poor Lease Maintenance

There are documented cases in Kansas of damage associated with inadequate lease maintenance and illegal operation of pits. These cases commonly result in contamination of soil and surface water with high levels of chlorides as well as long-term chloride contamination of ground water.

Temple Oil Company and Wayside Production Company operated a number of oil production leases in Montgomery County. The leases were operated with illegally maintained saltwater containment ponds, improperly abandoned reserve pits, unapproved emergency saltwater pits, and improperly abandoned saltwater pits. Numerous oil and saltwater spills were recorded during operation of the sites. Documentation of these incidents started in 1977 when adjacent landowners began to complain about soil pollution, vegetation kills, fish kills, and pollution of freshwater streams due to oil and saltwater runoff from these sites. The leases also contain a large number of abandoned, unplugged wells, which may pose a threat to ground water.[42] Complaints were received by the Conservation Division, Kansas Department of Health and the Environment (KDHE), Montgomery County Sheriff, and Kansas Fish and Game Commission. A total of 39 violations on these leases were documented between 1983 and 1984.

A sample taken by KDHE from a 4 1/2-foot test hole between a freshwater pond and a creek on one lease showed chloride concentrations of 65,500 ppm. Water samples taken from pits on other leases showed chloride concentrations ranging from 5,000 to 82,000 ppm.

The Kansas Corporation Commission (KCC) issued an administrative order in 1984, fining Temple and Wayside a total of $80,000. Initially, $25,000 was collected, and the operators could reapply for licenses to operate in Kansas in 36 months if they initiated adequate corrective measures. The case is currently in private litigation. The KCC found that no progress had been made towards bringing the leases into compliance and, therefore, reassessed the outstanding $55,000 penalty. The KCC has since sought judical enforcement of that penalty in the District Court, and a journal entry has been signed and was reviewed by the KCC and is now ready to be filed in District Court. Additionally, in a separate lawsuit between the landowners, the lessors, and the Temples regarding operation of the leases, the landowners were successful and the leases have reverted back to the landowners. The new operators are prevented from operating without KCC authority. (KS 01)[43]

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42 Comments in the Docket by the Kansas Corporation Commission (Beatrice Stong) pertain to KS 01. With regard to the abandoned wells, Kansas Corporation Commission states that these wells are "...cemented from top to bottom...", they have "...limited resource energy..." and the static fluid level these reservoirs could sustain are "...well below the location of any drinking or usable water."

43 References for case cited: The Kansas Corporation Commission Court Order describing the evidence and charges against the Temple Oil Co., 5/17/84.

This case represents habitual violation of Kansas regulations.

On January 31, 1986, the Kansas Department of Health and the Environment (KDHE) inspected the Reitz lease in Montgomery County, operated by Marvin Harr of El Dorado, Arkansas. The lease included an unpermitted emergency pond containing water that had 56,500 ppm chlorides. A large seeping area was observed by KDHE inspectors on the south side of the pond, allowing the flow of salt water down the slope for about 30 feet. The company was notified and was asked to apply for a permit and install a liner because the pond was constructed of sandy clay and sandstone. The operator was directed to immediately empty the pond and backfill it if a liner was not installed. On February 24, the lease was reinspected by KDHE and the emergency pond was still full and actively seeping. It appeared that the lease had been shut down by the operator. A "pond order" was issued by KDHE requiring the company to drain and backfill the pond. On April 29, the pond was still full and seeping.

Water samples taken from the pit by KDHE showed chloride concentrations of from 30,500 ppm (4/29/86) to 56,500 ppm (1/31/86). Seepage from the pit showed chloride concentrations of 17,500 ppm (2/24/86). The Kansas Department of Health and the Environment stated that "...the use of the pond...has caused or is likely to cause pollution to the soil and the waters of the State." An administrative penalty of $500 was assessed against the operator, and it was ordered that the pond be drained and backfilled. (KS 08)[44]

This activity is in violation of current Kansas regulations.

Such incidents are a recognized problem in Kansas. On May 13, 1987, the Kansas Corporation (KCC) added new lease maintenance rules to their oil and gas regulations. These new rules require permits for all pits, drilling and producing, and require emptying of emergency pits within 48 hours. Spills must now be reported in 24 hours. The question of concern is how stringently these rules can be enforced, in the light of the evident reluctance of some operators to comply. (See Table VII-7.)

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44 References for case cited: Kansas Department of Health and Environment Order assessing civil penalty, in the matter of Marvin Harr, Case No. 86-E-77, 6/10/86. Pond Order issued by Kansas Department of Health and Environment, in the matter of Marvin Harr, Case No. 86-PO-008, 3/21/86.

Unlined Reserve Pits

Problems with unlined reserve pits are illustrated in the following cases.

Between February 9 and 27, 1986, the Elliott #1 was drilled on the property of Mr. Lawrence Koehling. The Hutchinson Salt member, an underground formation, was penetrated during the drilling of Elliott #1. The drilling process dissolved between 100 and 200 cubic feet of salt, which was disposed of in the unlined reserve pit. The reserve pit lies 200 feet away from a well used by Mr. Koehling for his ranching operations. Within a few weeks of the drilling of the Elliott #1, Mr. Koehling's nearby well began to pump water containing a saltwater drilling fluid.

Ground water on the Koehling ranch has been contaminated with high levels of chlorides allegedly because of leaching of the reserve pit fluids into the ground water. Water samples taken from the Koehling livestock water well by the KCC Conservation Division showed a chloride concentration of 1650 mg/L. Background concentrations of chlorides were in the range of 100 to 150 ppm. It is stated in a KCC report, dated November 1986, that further movement of the saltwater plume can be anticipated, thus polluting the Koehling domestic water well and the water well used by a farmstead over 1 mile downstream from the Koehling ranch. It is also stated in this KCC report that other wells drilled in the area using unlined reserve pits would have similarly affected the groundwater.

The KCC now believes the source of ground-water contamination is not the reserve pit from the Elliott #1. The KCC has drilled two monitoring wells, one 10 feet from the edge of the reserve pit location and the other within 400 feet of the affected water well, between the affected well and the reserve pit. The monitoring well drilled 10 feet from the reserve pit site tested 60 ppm chlorides. (EPA notes that it is not known if this monitoring well was located upgradient from the reserve pit.) The monitoring well drilled between the affected well and the reserve pit tested 750 ppm chlorides. (EPA notes that the level of chlorides in this monitoring well is more than twice the level of chlorides allowed under the EPA drinking water standards). The case is still open, pending further investigation. EPA believes that the evidence presented to date does not refute the earlier KCC report, which cited the reserve pit as the source of ground-water contamination, since the recent KCC report does not suggest an alternative source of contamination. (KS 05)[45]

Unpermitted reserve pits are in violation of current Kansas regulations.

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45 References for case cited: Summary Report, Koehling Water Well Pollution, 22-10-15W, KCC, Conservation Division, Jim Schoof, Chief Engineer, 11/86.

Mr. Leslie, a private landowner in Kansas, suspected that chloride contamination of a natural spring occurred as a result of the presence of an abandoned reserve pit used when Western Drilling Inc. drilled a well (Leslie #1) at the Leslie Farm. Drilling in this area required penetration of the Hutchinson Salt member, during which 200 to 400 cubic feet of rock salt was dissolved and discharged into the reserve pit. The ground in the area consists of highly unconsolidated soils, which would allow for migration of pollutants into the ground water. Water at the top of the Leslie #1 had a conductivity of 5,050 umhos. Conductivity of the spring water equaled 7,250 umhos. As noted by the KCC, "very saline water" was coming out of the springs. Conductivity of 2,000 umhos will damage soil, precluding growth of vegetation. No fines were levied in this case as there were no violations of State rules and regulations. The Leslies filed suit in civil court and won their case for a total of $11,000 from the oil and gas operator.[46] (KS 03)[47]

Current Kansas regulations call for a site-by-site evaluation to determine if liners for reserve pits are appropriate.

Problems with Injection Wells

Problems with injection wells can occur as a result of inadequate maintenance, as illustrated by the following case.

On July 12, 1981, the Kansas Department of Health and the Environment (KDHE) received a complaint from Albert Richmeier, a landowner operating an irrigation well in the South Solomon River valley. His irrigation well had encountered salty water. An irrigation well belonging to an adjacent landowner, L. M. Paxson, had become salty in the fall of 1980. Oil has been produced in the area since 1952, and since 1962 secondary recovery by water flooding has been used. Upon investigation by the KDHE, it was discovered that the cause of the pollution was a saltwater injection well nearby, operated by Petro-Lewis. A casing profile caliper log was run by an operator-contractor under the direction of KDHE staff, which revealed numerous holes in the casing of the injection well. The producing formation, the Kansas City-Lansing, requires as much as 800 psi at the wellhead while injecting fluid to create a profitable enhanced oil recovery project. To remediate the contamination, the alluvial aquifer was pumped, and the initial chloride concentration of 6,000 mg/L was lowered to 600 to 700 mg/L in a year's time. Chloride contamination in some areas was lowered from 10,000 mg/L to near background levels. However, a contamination problem continues in the Paxson well, which shows chlorides in the range of 1,100 mg/L even though KDHE, through pumping, has tried to reduce the

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46 API states that KDHE had authority over pits at this time. The KCC now requires permits for such pits.

47 Reference for case cited: Final Report, Gary Leslie Saltwater Pollution Problem, Kingman County, KCC Conservation Division, Jim Schoof, Chief Engineer, 9/86. Contains letters, memos, and analysis pertaining to the case.

concentration. After attempts at repair, Petro-Lewis decided to plug the injection well.[48] (KS 06)[49]

Operation of such a well would violate current Kansas and UIC regulations.

TEXAS/OKLAHOMA

The Texas/Oklahoma zone includes these two States, both of which are large producers of oil and gas. As of December 1986, Texas ranked as the number one producer in the U.S. among all oil-producing States. Because of scheduling constraints, research on this zone concentrated on Texas, and most of the damage cases collected come from that State.

Operations

Oil and gas operations in Texas and Oklahoma began in the 1860s and are among the most mature and extensively developed in the U.S. These two States include virtually all types of operations, from large-scale exploratory projects and enhanced recovery projects to marginal small-scale stripper operations. In fact, the Texas/Oklahoma zone includes most of the country's stripper well production. Because of their maturity, many operations in the area generate significant quantities of associated produced water.

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48 Comments in the Docket by the KCC (Bill Bryson) pertain to KS 06. KCC states that of the affected irrigation wells, one is "...back in service and the second is approaching near normal levels as it continues to be pumped." API states that Kansas received primacy for the UIC program in 1984.

49 References for case cited: Richmeier Pollution Study, Kansas Department of Health and Environment, G. Blackburn and W. R. Bryson, 1983.

Development of oil and gas reserves remains active. In 1985, some 9,176 new wells were completed in Oklahoma, 385 of which were exploration wells. In Texas in the same year, 25,721 wells were completed on shore, 3,973 of which were exploration wells. The average depth of wells in the two areas is comparable: Oklahoma, 4,752 feet; Texas, 4,877 feet. Because the scale and character of operations varies so widely, cases of environmental damage from this zone are also varied and are not limited to any particular type of operation.

Types of Operators

Major operators are the principal players in exploration and development of deep frontiers and capital-intensive secondary and tertiary recovery projects. As elsewhere, the major companies have the best record of compliance with environmental requirements of all types; they are least likely to cut corners on operations, tend to use high-quality materials and methods when drilling, and are generally responsible in handling well abandonment obligations.

Smaller independent operators in the zone are more susceptible to fluctuating market conditions. They may lack sufficient capital to purchase first-quality materials and employ best available operating methods.

Major Issues

Discharge of Produced Water and Drilling Muds into Bays and Estuaries of the Texas Gulf Coast

Texas allows the discharge of produced water into tidally affected

estuaries and bays of the Gulf Coast from nearby onshore development. Cases in which permitted discharges have created damage include:

> In Texas, oil and gas producers operating near the Gulf Coast are permitted to discharge produced water into surface streams if they are found to be tidally affected. Along with the produced water, residual production chemicals and organic constituents may be discharged, including lead, zinc, chromium, barium, and water-soluble polycyclic aromatic hydrocarbons (PAHs). PAHs are known to accumulate in sediment, producing liver and lip tumors in catfish and affecting mixed function oxidase systems of mammals, rendering a reduced immune response. In 1984, a study conducted by the U.S. Fish and Wildlife Service of sediment in Tabb's Bay, which receives discharged produced water as well as discharges from upstream industry (i.e., discharges from ships in the Houston Ship Channel), indicates severe degradation of the environment by PAH contamination. Sediment was collected from within 100 yards of several tidal discharge points of oil field produced water. Analytical results of these sediments indicated severe degradation of the environment by PAH contamination. The study noted that sediments contained no benthic fauna, and because of wave action, the contaminants were continuously resuspended, allowing chronic exposure of contaminants to the water column. It is concluded by the U.S. Fish and Wildlife Service that shrimp, crabs, oysters, fish, and fish-eating birds in this location have the potential to be heavily contaminated with PAHs. While these discharges have to be within Texas Water Quality Standards, these standards are for conventional pollutants and do not consider the water soluble components of oil that are in produced water such as PAHs.[50] (TX 55)[51]

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50 NPDES permits have been applied for, but EPA has not issued permits for these discharges on the Gulf Coast. The Texas Railroad Commission (TRC) issues permits for these discharges. The TRC disagrees with the source of damage in this case.

51 References for case cited: Letter from U.S. Department of the Interior, Fish and Wildlife Service, signed by H. Dale Hall, to Railroad Commission of Texas, discussing degradation of Tabb's Bay because of discharge of produced water in upstream estuaries; includes lab analysis for polycyclic aromatic hydrocarbons in Tabb's Bay sediment samples. Texas Railroad Commission Proposal for Decision on Petronilla Creek case documenting that something other than produced water is killing aquatic organisms in the creek. (Roy Spears, Texas Parks and Wildlife, did LC50 study on sunfish and sheepshead minnows using produced water and Aranssas Bay water. Produced water diluted to proper salinity caused mortality of 50 percent. (Seawater contains 19,000 ppm chlorides.)

These discharges are not in violation of existing regulations.

Produced water discharges contain a high ratio of calcium ions to magnesium ions. This high ratio of calcium to magnesium has been found by Texas Parks and Wildlife officials to be lethal to common Atlantic croaker, even when total salinity levels are within tolerable limits. In a bioassay study conducted by Texas Parks and Wildlife, this fish was exposed to various ratios of calcium to magnesium, and it was found that in 96-hour LC50 studies, mortality was 50 percent when exposed to calcium-magnesium ratios of 6:1, the natural ratio being 1:3. Nearly all of oil field produced water discharges on file with the Army Corps of Engineers in Galveston contain ratios exceeding the 6:1 ratio, known to cause mortality in Atlantic croaker as established by the LC50 test.[52] (TX 31)[53]

These discharges are not in violation of current regulations.

Until very recently, the Texas Railroad Commission (TRC) allowed discharge of produced water into Petronilla Creek, parts of which are 20 miles inland and not tidally affected.

For over 50 years, oil operators (including Texaco and Amoco) have been allowed to discharge produced water into Petronilla Creek, a supposedly tidally influenced creek. Discharge areas were as much as 20 miles inland and contained fresh water. In 1981, the pollution of Petronilla Creek from discharge of produced water became an issue when studies done by the Texas Parks and Wildlife and Texas Department of Water Resources documented the severe degradation of the water and damage to native fish and vegetation. All freshwater species of fish and vegetation were dead because of exposure to toxic constituents in discharge liquid. Portions of the creek were black or bright orange in color. Heavy oil slicks and oily slime were observable along discharge areas.

Impacts were observed in Baffin Bay, into which the creek empties. Petronilla Creek is the only freshwater source for Baffin Bay, which is a nursery for many fish and shellfish in the Gulf of Mexico. Sediments in Baffin Bay show elevated levels of toxic constituents found in Petronilla Creek. For 5 years, the Texas Department of Water Resources and Texas Parks and Wildlife, along with environmental groups, worked to have the discharges stopped. In 1981, a hearing was held by the Texas Railroad Commission (TRC). The conclusion of the hearing was that discharge of the produced water plus disposal of other trash by the public was degrading Petronilla Creek. The TRC initiated a joint committee (Texas Department of Water Resources, Texas Parks and Wildlife Department, and TRC) to establish the source of the trash, clean up

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52 API comments in the Docket pertain to TX 31. API states that models show that "...rapid mixing in Bay waters results in no pollution to Bay waters as a whole from calcium ions or from the calcium-magnesium ratio."

53 References for case cited: Toxic Effects of Calcium on the Atlantic Croaker: An Investigation of One Component of Oil Field Brine, by Kenneth N. Knudson and Charles E. Belaire, undated.

trash from the creek, and conduct additional studies. After this work was completed, a second hearing was held in 1984. The creek was shown to contain high levels of chromium, barium, oil, grease, and EPA priority pollutants naphthalene and benzene. Oil operators stated that a no dumping order would put them out of business because oil production in this area is marginal. In 1986, the TRC ordered a halt to discharge of produced water into nontidal portions of Petronilla Creek. (TX 29)[54]

Although discharges are now prohibited in this creek, they are allowed in other tidally affected areas.

Long-term environmental impacts associated with this type of discharge are unknown, because of limited documentation and analysis. Bioaccumulation of heavy metals in the food chain of estuaries could potentially affect human health through consumption of crabs, clams, and other foods harvested off the Texas Gulf Coast.

Alternatives to coastal discharge do exist. They include underground injection of produced water and use of produced water tanks. While the Texas Railroad Commission has not stopped the practice of coastal discharge, it is currently evaluating the need to preclude this type of discharge by collecting data from new applications, and it is seeking delegation of the NPDES program under the Federal Clean Water Act. The TRC currently asks applicants for tidal discharge permits to analyze the produced water to be discharged for approximately 20 to 25 constituents.

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54 References for case cited: The Effects of Brine Water Discharges on Petronilla Creek, Texas Parks and Wildlife Department, 1981. Texas Department of Water Resources interoffice memorandum documenting spills in Petronilla Creek from 1980 to 1983. The Influence of Oilfield Brine Water Discharges on Chemical and Biological Conditions in Petronilla Creek, by Frank Shipley, Texas Department of Water Resources, 1984. Letter from Dick Whittington, EPA, to Richard Lowerre, documenting absence of NPDES permits for discharge to Petronilla Creek. Final Order of TRC, banning discharge of produced water to Petronilla Creek, 6/23/86. Numerous letters, articles, legal documents, on Petronilla Creek case.

Leaching of Reserve Pit Constituents into Ground Water

Leaching of reserve pit constituents into ground water and soil is a problem in the Texas/Oklahoma zone. Reserve pit liners are generally not required in Texas and Oklahoma. When pits are constructed in permeable soil without liners, a higher potential exists for migration of reserve pit constituents into ground water and soil. Although pollutant migration may not always occur during the active life of the reserve pit, problems can occur after closure when dewatered drilling mud begins to leach into the surrounding soil. Pollutants may include chlorides, sodium, barium, chromium, and arsenic.

On November 20, 1981, the Michigan-Wisconsin Pipe Line Company began drilling an oil and gas well on the property of Ralph and Judy Walker. Drilling was completed on March 27, 1982. Unlined reserve pits were used at the drill site. After 2 months of drilling, the water well used by the Walkers became polluted with elevated levels of chloride and barium (683 ppm and 1,750 ppb, respectively). The Walkers were forced to haul fresh water from Elk City for household use. The Walkers filed a complaint with the Oklahoma Corporation Commission (OCC), and an investigation was conducted. The Michigan-Wisconsin Pipe Line Co. was ordered to remove all drilling mud from the reserve pit.

In the end, the Walkers retained a private attorney and sued Michigan-Wisconsin for damages sustained because of migration of reserve pit fluids into the freshwater aquifer from which they drew their domestic water supply. The Walkers won their case and received an award of $50,000.[55] (OK 08)[56]

Constructing a reserve pit over a fractured shale, as in this case, is a violation of OCC rules.

In 1973, Horizon Oil and Gas drilled an oil well on the property of Dorothy Moore. As was the common practice, the reserve pit was dewatered, and the remaining mud was buried on site. In 1985-86, problems from the buried reserve pit waste began to appear. The reserve pit contents

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55 API states that the Oklahoma Corporation Commission is in the process of developing regulations to prevent leaching of salt muds into ground water.

56 References for case cited: Pretrial Order, Ralph Gail Walker and Judy Walker vs. Michigan-Wisconsin Pipe Line Company and Big Chief Drilling Company, U.S. District Court, Western District of Oklahoma, #CIV-82-1726-R. Direct Examination of Stephen G. McLin, Ph. D. Direct Examination of Robert Hall. Direct Examination of Laurence Alatshuler, M. D. Lab results from Walker water well.

were seeping into a nearby creek and pond. The surrounding soil had very high chloride content as established by Dr. Billy Tucker, an agronomist and soil scientist. Extensive erosion around the reserve pit became evident, a common problem with high-salinity soil. Oil slicks were visible in the adjacent creek and pond. An irrigation well on the property was tested by Dr. Tucker and was found to have 3000 ppm chlorides; however, no monitoring wells had been drilled to test the ground water prior to the drilling of the oil well, and background levels of chlorides were not established. Dorothy Moore has filed civil suit against the operator for damages sustained during the oil and gas drilling activity. The case is pending.[57] (OK 02)[58]

Oklahoma performance standards prohibit leakage of reserve pits into ground water.

<u>Chloride Contamination of Ground Water from Operation of Injection Wells</u>

The Texas/Oklahoma zone contains a large number of injection wells used both for disposal of produced water and for enhanced or tertiary recovery projects. This large number of injection wells increases the potential for injection well casing leaks and the possibility of ground water contamination.

The Devore #1, a saltwater injection well located on the property of Verl and Virginia Hentges, was drilled in 1947 as an exploratory well. Shortly afterwards, it was permitted by the Oklahoma Corporation Commission (OCC) as a saltwater injection well. The injection formation, the Layton, was known to be capable of accepting 80 barrels per hour at 150 psi. In 1984, George Kahn acquired the well and the OCC granted an exception to Rule 3-305, Operating Requirements for Enhanced Recovery Injection and Disposal Wells, and permitted the well to inject 2,000 barrels per day at 400 psi. Later in 1984, it appeared that there was saltwater migration from the intended injection zone of the Devore #1 to the surface.[59] The Hentges alleged that the migrating salt water had polluted the ground water used on their ranch.

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57 API comments in the Docket pertain to OK 02. API states that "...there is no evidence that there has been any seepage whatsoever into surface water." API states that there are no irrigation wells on Mrs. Moore's farm. Further, it states that erosion has been occurring for years and is the "...result of natural conditions coupled with the failure of Mrs. Moore to repair terraces to prevent or limit such erosion." API has not provided supporting documentation.

58 References for case cited: Extensive soil and water analysis results collected and interpreted by Dr. Billy Tucker, agronomist and soil scientist, Stillwater, Okla. Correspondence and conversation with Randall Wood, private attorney, Stack and Barnes, Oklahoma City, Okla.

59 Comments by API in the Docket pertain to OK 06. API states that "...tests on the well pressure test and tracer logs indicate the injection well is not a source of salt water." API has not provided documentation with this statement.

In addition, they alleged that the migrating salt water was finding its way to the surface and polluting Warren Creek, a freshwater stream used by downstream residents for domestic water. Salt water discharged to the surface had contaminated the soil and had caused vegetation kills. A report by the OCC concluded that "...the Devore #1 salt water disposal well operations are responsible for the contaminant plume in the adjacent alluvium and streams." The OCC required that a workover be done on the well. The workover was completed, and the operator continued to dispose of salt water in the well. The Hentges then sought private legal assistance and filed a lawsuit against George Kahn, the operator, for $300,000 in actual damages and $3,000,000 in punitive damages. The lawsuit is pending, scheduled for trial in October 1987.[60] (OK 06)[61]

Although at the time, the OCC permitted injection into the well at pressures that may have polluted the ground water, Oklahoma prohibits any contamination of drinking-water aquifers.

Illegal Disposal of Oil and Gas Wastes

Illegal disposal of oil and gas exploration and production wastes is a common problem in the Texas/Oklahoma zone. Illegal disposal can take many forms, including breaching of reserve pits, emptying of vacuum trucks into fields and ditches, and draining of produced water onto the land surface. Damage to surface soil, vegetation, and surface water may result as illustrated by the examples below.

On May 16, 1984, Esenjay Petroleum Co. had completed the L.W. Bing #1 well at a depth of 9,900 feet and had hired T&L Lease Service to clean up the drill site. During cleanup, the reserve pit, containing high-chromium drilling mud, was breached by T&L Lease Service, allowing drilling mud to flow into a tributary of Hardy Sandy Creek. The drilling mud was up to 24 inches deep along the north bank of Hardy Sandy. Drilling mud had been pushed into the trees and brush adjacent to the drill site. The spill was reported to the operator and the Texas Railroad Commission (TRC). The TRC ordered cleanup, which began on May 20.

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60 API states that the operator now believes old abandoned saltwater pits to be the source of contamination as the well now passes UIC tests.

61 References for case cited: Remedial Action Plan for Aquifer Restoration within Section #2, Township 21 North, Range 2 West, Noble County, Oklahoma, by Stephen G. McLin, Ph. D. Surface Pollution at the De Vore #1 Saltwater Disposal Site, Oklahoma Corporation Commission, 1986. District Court of Noble County, Amended Petition, Verl E. Hentges and Virginia L. Hentges vs. George Kahn, #C-84-110, 7/25/85. Lab analysis records of De Vore well from Oklahoma Corporation Commission and Southwell Labs. Communication with Alan DeVore, plaintiffs' attorney.

Because of high levels of chromium contained in the drilling mud, warnings were issued by the Lavaca-Navidad River Authority to residents and landowners downstream of the spill as it represented a possible health hazard to cattle watering from the affected streams. The River Authority also advised against eating the fish from the affected waters because of the high chromium levels in the drilling mud. (TX 21)[62]

This discharge was a violation of State and Federal regulations.

On September 15, 1983, TXO Production Company began drilling its Dunn Lease Well No. B2 in Live Oak County. On October 5, 1983, employees of TXO broke the reserve pit levee and began spreading drilling mud downhill from the site, towards the fence line of property owned by the Dunns. By October 9, the mud had entered the draw that flows into two stock tanks on the Dunn property. On November 24 and 25, dead fish were observed in the stock tank. On December 17, Texas Parks and Wildlife documented over 700 fish killed in the stock tanks on the Dunn property. Despite repeated requests by the Dunns, TXO did not clean up the drilling mud and polluted water from the Dunn property.

Lab results from TRC and Texas Department of Health indicated that the spilled drilling mud was high in levels of arsenic, barium, chromium, lead, sulfates, other metals, and chlorides. In February 1984, the TRC stated that the stock tanks contained unacceptable levels of nitrogen, barium, chromium, and iron, and that the chemicals present were detrimental to both fish and livestock. (The Dunns water their cows at this same stock tank.) After further analysis, the TRC issued a memorandum stating that the fish had died because of a cold front moving through the area, in spite of the fact that the soil, sediment, and water in and around the stock pond contained harmful substances. Ultimately, TXO was fined $1,000 by the TRC, and TXO paid the Dunns a cash settlement for damages sustained.[63] (TX 22)[64]

This activity was in violation of Texas regulations.

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62 References for case cited: Memorandum from Lavaca-Navidad River Authority documenting events of Esenjay reserve pit discharge, 6/27/84, signed by J. Henry Neason. Letter to TRC from Lavaca-Navidad River Authority thanking the TRC for taking action on the Esenjay case, "Thanks to your enforcement actions, we are slowly educating the operators in this area on how to work within the law." Agreed Order, Texas Railroad Commission, #2-83,043, 11/12/84, fining Esenjay $10,000 for deliberate discharge of drilling muds. Letter from U.S. EPA to TRC inviting TRC to attend meeting with Esenjay Petroleum to discuss discharge of reserve pit into Hardy Sandy Creek, 6/1/84, signed by Thomas G. Giesberg. Texas Railroad Commission spill report on Esenjay operations, 5/18/84.

63 API states that the fish died from oxygen depletion of the water. The Texas Railroad Commission believes that the fish died from exposure to cold weather.

64 References for case cited: Texas Railroad Commission Motion to Expand Scope of Hearing, #2-82,919, 6/29/84. Texas Railroad Commission Agreed Order, #2-82,919, 12/17/84. Analysis by Texas Veterinary Medical Diagnostic Laboratory System on dead fish in Dunn stock tank. Water and soil sample analysis from the Texas Railroad Commission. Water and soil samples from the Texas Department of Health. Letter from Wendell Taylor, TRC, to Jerry Mullican, TRC, stating that the fish kill was the result of cold weather, 7/13/84. Miscellaneous letters and memos.

NORTHERN MOUNTAIN

The Northern zone includes Idaho, Montana, and Wyoming. Idaho has no commercial production of oil or gas. Montana has moderate oil and gas production. Wyoming has substantial oil and gas production and accounts for all the damage cases discussed in this section.

Operations

Significant volumes of both oil and gas are produced in Wyoming. Activities range from small, marginal operations to major capital- and energy-intensive projects. Oil production comes both from mature fields producing high volumes of produced water and from newly discovered fields, where oil/water ratios are still relatively low. Gas production comes from mature fields as well as from very large new discoveries.

Although the average new well drilled in Wyoming in 1985 was about 7,150 feet, exploration in the State can be into strata as deep as 25,000 feet. In 1985, 1,332 new wells were completed in Wyoming, of which 541 were exploratory.

Types of Operators

Because of the capital-intensive nature of secondary and tertiary recovery projects and large-scale drilling projects, many operations in the State are conducted by the major oil companies. These companies are likely to implement environmental controls properly during drilling and completion and are generally responsible in carrying out their well abandonment obligations. Independents also operate in Wyoming, producing

a significant amount of oil and gas in the State. Independent operators may be more vulnerable to fluctuating market conditions and may be more likely to maintain profitability at the expense of environmental protection.

Major Issues

Illegal Disposal of Oil and Gas Wastes

Wyoming Department of Environmental Quality officials believe that illegal disposal of wastes is the most pervasive environmental problem associated with oil and gas operations in Wyoming. Enforcement of State regulations is made difficult as resources are scarce and areas to be patrolled are large and remote. (See Table VII-7.)

Altex Oil Company and its predecessors have operated an oil production field for several decades south of Rozet, Wyoming. (Altex purchased the property in 1984.) An access road runs through the area, which, according to Wyoming Department of Environmental Quality (WDEQ), for years was used as a drainage for produced water from the oil field operations.

In August of 1985, an official with WDEQ collected soil samples from the road ditch to ascertain chloride levels because it had been observed that trees and vegetation along the road were dead or dying. WDEQ analysis of the samples showed chloride levels as high as 130,000 ppm. The road was chained off in October of 1985 to preclude any further illegal disposal of produced water.[65] (WY 03)[66]

In early October 1985, Cities Service Oil Company had completed drilling at a site northeast of Cheyenne on Highway 85. The drilling contractor, Z&S Oil Construction Company, was suspected of illegally disposing of drilling fluids at a site over a mile away on the Pole Creek Ranch. An employee of Z&S had given an anonymous tip to a County detective. A stake-out of the

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65 Comments in the Docket from the Wyoming Oil and Gas Conservation Commission (WOGCC) (Mr. Don Basko) pertain to WY 03. WOGCC states that "...not all water from Altex Oil producing wells... caused the contamination problem." Further, WOGCC states that "Illegal dumping, as well as a flow line break the previous winter, had caused a high level of chloride in the soil which probably contributed to the sagebrush and cottonwood trees dying."

66 References for case cited: Analysis of site by the Wyoming Department of Environmental Quality (WDEQ), Quality Division Laboratory, File #ej52179, 12/6/85. Photographs of dead and dying cottonwood trees and sagebrush in and around site. Conversation with WDEQ officials.

illegal operation was made with law enforcement and WDEQ personnel. Stake-out personnel took samples and photos of the reserve pit and the dump site. During the stake-out, vacuum trucks were witnessed draining reserve pit contents down a slope and into a small pond on the Pole Creek Ranch. After sufficient evidence had been gathered, arrests were made by Wyoming law enforcement personnel, and the trucks were impounded. The State sued Z&S and won a total of $10,000. (WY 01)[67]

This activity was in violation of Wyoming regulations.

During the week of April 8, 1985, field personnel at the Byron/Garland field operated by Marathon Oil Company were cleaning up a storage yard used to store drums of oil field chemicals. Drums containing discarded production chemicals were punctured by the field employees and allowed to drain into a ditch adjacent to the yard. Approximately 200 drums containing 420 gallons of fluid were drained into the trench. The chemicals were demulsifiers, reverse demulsifiers, scale and corrosion inhibitors, and surfactants. Broken transformers containing PCBs were leaking into soil in a nearby area. Upon discovery of the condition of the yard, Wyoming Department of Environmental Quality (WDEQ) ordered Marathon to begin cleanup procedures. At the request of the WDEQ, ground-water monitors were installed, and monitoring of nearby Arnoldus Lake was begun. The State filed a civil suit against Marathon and won a $5000 fine and $3006 in expenses for lab work.[68] (WY 05)[69]

This activity was in direct violation of Wyoming regulations.

Reclamation Problems

Although Wyoming's mining industry has rules governing reclamation of sites, no such rules exist covering oil and gas operations. As a result, reclamation on privately owned land is often inadequate or entirely lacking, according to WDEQ officials. By contrast, reclamation on Federal lands is believed to be consistently more thorough, since Federal

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67 References for case cited: WDEQ memorandum documenting chronology of events leading to arrest of Z&S employees and owners. Lab analysis of reserve pit mud and effluent, and mud and effluent found at dump site. Consent decree from District Court of First Judicial District, Laramie County, Wyoming, docket #108-493, The People of the State of Wyoming vs. Z&S Construction Company. Photographs of vacuum trucks dumping at Pole Creek Ranch.

68 API states that the operator, thinking the drums had to be empty before transport offsite, turned the drums upside down and drained 420 gallons of chemicals into the trench.

69 References for case cited: Summary of Byron-Garland case by Marathon employee J. C. Fowler. List of drums, contents, and field uses. Cross-section of disposal trench area. Several sets of lab analyses. Map of Garland field disposal yard. Newspaper articles on incident. District court consent decree, The People of the State of Wyoming vs. Marathon Oil Company, #108-87.

leases specify reclamation procedures to be used on specific sites. WDEQ officials state that this will be of growing concern as the State continues to be opened up to oil and gas development.[70]

WDEQ officials have photographs and letters from concerned landowners, regarding reclamation problems, but no developed cases. The Wyoming Oil and Gas Conservation Commission submitted photographs documenting comparable reclamation on both Federal and private lands. The issue is at least partially related to drilling waste management, since improper reclamation of sites often involves inadequate dewatering of reserve pits before closure. As a result of this inadequate dewatering, reserve pit constituents, usually chlorides, are alleged to migrate up and out of the pit, making revegetation difficult. The potential also exists for migration of reserve pit constituents into ground water.

Discharge of Produced Water into Surface Streams

Because much of the produced water in Wyoming is relatively low in chlorides, several operations under the beneficial use provision of the Federal NPDES permit program are allowed to discharge produced water directly into dry stream beds or live streams. The practice of chronic discharge of low-level pollutants may be harmful to aquatic communities in these streams, since residual hydrocarbons contained in produced water appear to suppress species diversity in live streams.

A study was undertaken by the Columbia National Fisheries Research Laboratory of the U. S. Fish and Wildlife Service to determine the effect of continuous discharge of low-level oil effluent into a stream and the resulting effect on the aquatic community in the stream. The discharges to the stream contained 5.6 mg/L total hydrocarbons. Total hydrocarbons in the receiving sediment were 979 mg/L to 2,515 mg/L. During the study, samples were taken upstream

70 WOGCC disagrees with WDEQ on this statement.

and downstream from the discharge. Species diversity and community structure were studied. Water analysis was done on upstream and downstream samples. The study found a decrease in species diversity of the macrobenthos community (fish) downstream from the discharge, further characterized by total elimination of some species and drastic alteration of community structure. The study found that the downstream community was characterized by only one dominant species, while the upstream community was dominated by three species. Total hydrocarbon concentrations in water and sediment increased 40 to 55 fold downstream from the discharge of produced water. The authors of the study stated that "...based on our findings, the fisheries and aquatic resources would be protected if discharge of oil into fresh water were regulated to prevent concentrations in receiving streams water and sediment that would alter structure of macrobenthos communities." (WY 07)[71]

These discharges are permitted under NPDES.

SOUTHERN MOUNTAIN

The Southern Mountain zone includes the States of Nevada, Utah, Arizona, Colorado, and New Mexico. All five States have some oil and gas production, but New Mexico's is the most significant. The discussion below is limited to New Mexico.

Operations

Although hydrocarbon production is scattered throughout New Mexico, most comes from two distinct areas within the State: the Permian Basin in the southeast corner and the San Juan Basin in the northwest corner.

Permian Basin production is primarily oil, and it is derived from several major fields. Numerous large capital- and energy-intensive enhanced recovery projects within the basin make extensive use of CO_2 flooding. The area also contains some small fields in which production

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71 References for case cited: Petroleum Hydrocarbon Concentrations in a Salmonid Stream Contaminated by Oil Field Discharge Water and Effects on the Macrobenthos Community, by D.F. Woodward and R.G. Riley, U.S. Department of the Interior, Fish and Wildlife Service, Columbia National Fisheries Research Laboratory, Jackson, Wyoming, 1980; submitted to Transactions of the American Fisheries Society.

is derived from marginal stripper operations. This is a mature production area that is unlikely to see extensive exploration in the future. The Tucumcari Basin to the north of the Permian may, however, experience extensive future exploration if economic conditions are favorable.

The San Juan Basin is, for the most part, a large, mature field that produces primarily gas. Significant gas finds are still made, including many on Indian Reservation lands. As Indian lands are gradually opened to oil and gas development, exploration and development of the basin as a whole will continue and possibly increase.

Much of the State has yet to be explored for oil and gas. The average depth of new wells drilled in 1985 was 6,026 feet. The number of new wells drilled in 1985 was 1,734, of which 281 were exploratory.

Types of Operators

The capital- and energy-intensive enhanced recovery projects in the Permian Basin, as well as the exploratory activities under way around the State, are conducted by the major oil companies. Overall, however, the most numerous operators are small and medium-sized independents. Small independents dominate marginal stripper production in the Permian Basin. Production in the San Juan Basin is dominated by midsize independent operators.

Major Issues

Produced Water Pit and Oil Field Waste Pit Contents Leaching into Ground Water

New Mexico, unlike most other States, still permits the use of unlined pits for disposal of produced water. This practice has the potential for contamination of ground water.

In July 1985, a study was undertaken in the Duncan Oil Field in the San Juan Basin by faculty members in the Department of Chemistry at New Mexico State University, to analyze the potential for unlined produced water pit contents, including hydrocarbons and aromatic hydrocarbons, to migrate into the ground water. The oil field is situated in a flood plain of the San Juan River. The site chosen for investigation by the study group was similar to at least 1,500 other nearby production sites in the flood plain. The study group dug test pits around the disposal pit on the chosen site. These test pits were placed abovegradient and downgradient of the disposal pit, at 25- and 50-meter intervals. A total of 9 test pits were dug to a depth of 2 meters, and soil and ground-water samples were obtained from each test pit. Upon analysis, the study group found volatile aromatic hydrocarbons were present in both the soil and water samples of test pits downgradient, demonstrating migration of unlined produced water pit contents into the ground water.

Environmental impact was summarized by the study group as contamination of shallow ground water with produced water pit contents due to leaching from an unlined produced water disposal pit. Benzene was found in concentrations of 0.10 ppb. New Mexico Water Quality Control Commission standard is 10 ppb. Concentrations of ethylbenzene, xylenes, and larger hydrocarbon molecules were found. No contamination was found in test pits placed abovegradient from the disposal pit. Physical signs of contamination were also present, downgradient from the disposal pit, including black, oily staining of sands above the water table and black, oily film on the water itself. Hydrocarbon odor was also present. (NM 02)[72]

It is now illegal to dispose of more than five barrels per day of produced water into unlined pits in this part of New Mexico.

As a result of this study, the use of unlined produced water pits was limited by the State to wells producing no more than five barrels per day of produced water. While this is a more stringent requirement than the previous rule, the potential for contamination of ground water with hydrocarbons and chlorides still exists. It is estimated by individuals familiar with the industry in the State that 20,000 unlined emergency

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72 References for case cited: Hydrocarbons and Aromatic Hydrocarbons in Groundwater Surrounding an Earthen Waste Disposal Pit for Produced Water in the Duncan Oil Field of New Mexico, by G.A. Eiceman, J.T. McConnon, Masud Zaman, Chris Shuey, and Douglas Earp, 9/16/85. Polycyclic Aromatic Hydrocarbons in Soil at Groundwater Level Near an Earthen Pit for Produced Water in the Duncan Oil Field, by B. Davani, K. Lindley, and G.A. Eiceman, 1986. New Mexico Oil Conservation Commission hearing to define vulnerable aquifers, comments on the hearing record by Intervenor Chris Shuey, Case No. 8224.

produced water disposal pits are still in existence in the San Juan Basin area of New Mexico.[73]

New Mexico has experienced problems that may be due to centralized oil field waste disposal facilities:

Lee Acres "modified" landfill (meaning refuse is covered weekly instead of daily as is done in a "sanitary" landfill) is located 4.5 miles E-SE of Farmington, New Mexico. It is owned by the U.S. Bureau of Land Management (BLM). The landfill is approximately 60 acres in size and includes four unlined liquid-waste lagoons or pits, three of which were actively used. Since 1981, a variety of liquid wastes associated with the oil and gas industry have been disposed of in the lagoons. The predominant portion of liquid wastes disposed of in the lagoons was produced water, which is known to contain aromatic volatile organic compounds (VOCs). According to the New Mexico Department of Health and Environment, Environmental Improvement Division, 75 to 90 percent of the produced water disposed of in the lagoons originated from Federal and Indian oil and gas leases managed by BLM. Water produced on these leases was hauled from as far away as Nageezi, which is 40 miles from the Lee Acres site. Disposal of produced water in these unlined pits was, according to New Mexico State officials, in direct violation of BLM's rule NTL-2B, which prohibits, without prior approval, disposal of produced waters into unlined pits, originating on Federally owned leases. The Department of the Interior states that disposal in the lagoons was "...specifically authorized by the State of New Mexico for disposal of produced water." The State of New Mexico states that "There is no truth whatsoever to the assertion that the landfill lagoons were specifically authorized by the State of New Mexico for disposal of produced water." Use of the pits ceased on 4/19/85; 8,800 cubic yards of waste were disposed of prior to closure.

New Mexico's Environmental Improvement Division (NMEID) asserts that leachate from the unlined waste lagoons that contain oil and gas wastes has contributed to the contamination of several water wells in the Lee Acres housing subdivision located downgradient from the lagoons and downgradient from a refinery operated by Giant, located nearby. NMEID has on file a soil gas survey that documents extensive contamination with chlorinated VOCs at the landfill site. High levels of sodium, chlorides, lead, chromium, benzene, toluene, xylenes, chloroethane, and trichloroethylene were found in the waste lagoons. An electromagnetic terrain survey of the Lee Acres landfill site and surrounding area, conducted by NMEID, located a plume of contaminated ground water extending from the landfill. This plume runs into a plume of contamination known to exist, emanating from the refinery. The plumes have become mixed and are the source of

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73 Governor Carruthers refutes this and states that "Unlined pits in fresh water areas in Southeast New Mexico were banned beginning in 1956, with a general prohibition adopted in 1967." EPA notes that New Mexico still permits unlined pits to be used for disposal of produced water if the pit does not receive more than five barrels of produced water per day.

contamination of the ground water serving the Lee Acres housing subdivision.[74] One domestic well was sampled extensively by NMEID and was found to contain extremely high levels of chlorides and elevated levels of chlorinated VOCs, including trichloroethane. (Department of the Interior (DOI) states that it is unaware of any violations of New Mexico ground-water standards involved in this case. New Mexico states that State ground-water standards for chloride, total dissolved solids, benzene, xylenes, 1,1-dichloroethane, and ethylene dichloride have been violated as a result of the plume of contamination. In addition, the EPA Safe Drinking Water Standard for trichloroethylene has been violated.) New Mexico State officials state that "The landfill appears to be the principal source of chloride, total dissolved solids and most chlorinated VOCs, while the refinery appears to be the principal source of aromatic VOCs and ethylene dichloride."

During the period after disposal operations ceased and before the site was closed, access to the lagoons was essentially unrestricted. While NMEID believes that it is possible that non-oil and gas wastes illegally disposed of during this period may have contributed to the documented contamination, the primary source of ground-water contamination appears to be from oil and gas wastes.

The State has ordered BLM to provide public water to residents affected by the contamination, develop a ground-water monitoring system, and investigate the types of drilling, drilling procedures, and well construction methods that generated the waste accepted by the landfill. BLM submitted a motion-to-stay the order so as to include Giant Refining Company and El Paso Natural Gas in cleanup operations. The motion was denied. The case went into litigation. According to State officials, "The State of New Mexico agreed to dismiss its lawsuit only after the Bureau of Land Management agreed to conduct a somewhat detailed hydrogeologic investigation in a reasonably expeditious period of time. The lawsuit was not dismissed because of lack of evidence of contamination emanating from the landfill." The refinery company has completed an

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74 In a letter dated 8/20/87, Giant Refining Company states that "Benzene, toluene and xylenes are naturally occurring compounds in crude oil, and are consequently in high concentrations in the produced water associated with that crude oil. The only gasoline additive used by Giant that has been found in the water of a residential well is DCA (ethylene dichloride) which has also been found in the landfill plume." Giant also notes that the refinery leaks in the last 2 years resulted in less than 30,000 gallons of diesel being released rather than the 100,000 gallons stated by the Department of Interior in a letter to EPA of 8/11/87.

extensive hydrogeologic investigation and has implemented containment and cleanup measures.[75] (NM 05)[76]

Current New Mexico regulations prohibit use of unlined commercial disposal pits.

Damage to Ground Water from Inadequately Maintained Injection Wells

As in other States, New Mexico has experienced problems with injection wells.

A saltwater injection well, the BO-3, operated by Texaco, is used for produced water disposal for the Moore-Devonian oil field in southeastern New Mexico. Injection occurs at about 10,000 ft. The Ogallala aquifer, overlying the oil production formation, is the sole source of potable ground water in much of southeastern New Mexico. Dr. Daniel B. Stephens, Associate Professor of Hydrology at the New Mexico Institute of Mining and Technology, concluded that injection well BO-3 has contributed to a saltwater plume of contamination in the Ogallala aquifer. The plume is nearly 1 mile long and contains chloride concentrations of up to 26,000 ppm.

A local rancher sustained damage to crops after irrigating with water contaminated by this saltwater plume. In 1973, an irrigation well was completed satisfactorily on the ranch of Mr. Paul Hamilton, and, in 1977, the well began producing water with chlorides of 1,200 ppm. Mr. Hamilton's crops were severely damaged, resulting in heavy economic losses, and his farm property was foreclosed on. There is no evidence of crop damage from irrigation prior to 1977. Mr. Hamilton initiated a private law suit against Texaco for damages sustained to his ranch. Texaco argued that the saltwater plume was the result of leachate of brines from unlined brine disposal pits, now banned in the area. Dr. Stephens proved that if old pits in the vicinity,

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75 Comments in the Docket from BLM and the State of New Mexico pertain to NM 05. BLM states that the refinery upgradient from the subdivision is responsible for the contamination because of their "...extremely sloppy housekeeping practices..." which resulted in the loss of "...hundreds of thousands of gallons of refined product through leaks in their underground piping system." The Department of the Interior states that "There is, in fact, mounting evidence that the landfill and lagoons may have contributed little to the residential well contamination in the subdivisions." DOI states "...we strongly recommend that this case be deleted from the Damage Cases [Report to Congress]." "New Mexico states that "EID [Environmental Improvement Division] strongly believes that the Lee Acres Landfill has caused serious ground water contamination and is well worth inclusion in the Oil and Gas Damage Cases chapter of your [EPA] Report to Congress on Oil, Gas and Geothermal Wastes."

76 References for case cited: State of New Mexico Administrative Order No. 1005; contains water analysis for open pits, monitor wells, and impacted domestic wells. Motion-to-stay Order No. 1005. Denial of motion to stay. Newspaper articles. Southwest Research and Information Center, Response to Hearing before Water Quality Control Commission, 12/2/86. Letter to Dan Derkics, EPA, from Department of the Interior, refuting Lee Acres damage case, 8/11/87. Letter to Dan Derkics, EPA, from NMEID, refuting Department of the Interior letter of 8/11/87, dated 8/18/87. Letter to Dan Derkics, EPA, from Giant Refining Company, 8/20/87.

previously used for saltwater disposal, had caused the contamination, high chloride levels would have been detected in the irrigation well prior to 1977. Dr. Stephens also demonstrated that the BO-3 injection well had leaked some 20 million gallons of brine into the fresh ground water, causing chloride contamination of the Ogallala aquifer from which Mr. Hamilton drew his irrigation water. Based on this evidence a jury awarded Mr. Hamilton a cash settlement from Texaco for damages sustained both by the leaking injection well and by the abandoned disposal pits. The well has had workovers and additional pressure tests since 1978. The well is still in operation, in compliance with UIC regulations. (NM 01)[77]

Current UIC regulations require mechanical integrity testing every 5 years for all Class II wells.

The well in the above case was tested for mechanical integrity several times during the course of the trial, during which the plaintiff's hydrologist, after contacting the Texas Railroad Commission, discovered that this injection well would have been classed as a failed well using criteria established by the State of Texas for such tests. However, at the time, the well did not fail the test using criteria established by the State of New Mexico. Both States have primacy under the UIC program.

WEST COAST

The West Coast zone includes Washington, Oregon, and California. Of the three states, California has the most significant hydrocarbon production; Washington and Oregon have only minor oil and gas activity. Damage cases were collected only in California.

Operations

California has a diverse oil and gas industry, ranging from stripper production in very mature fields to deep exploration and large enhanced recovery operations. Southern California and the San Joaquin Valley are dominated by large capital- and energy-intensive enhanced recovery

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77 References for case cited: Oil-Field Brine Contamination - A Case Study, Lea Co. New Mexico, from Selected Papers on Water Quality and Pollution in New Mexico - 1984; proceedings of a symposium, New Mexico Bureau of Mines and Resources.

projects, while the coastal fields are experiencing active exploration. California's most mature production areas are in the lower San Joaquin Valley and the Sacramento Basin. The San Joaquin produces both oil and gas. The Sacramento Valley produces mostly gas.

The average depth of new wells drilled in California in 1985 was 4,176 feet. Some 3,413 new wells were completed in 1985, 166 of which were exploratory.

Types of Operators

Operators in California range from small independents to major producers. The majors dominate capital- and energy-intensive projects, such as coastal development and large enhanced recovery projects. Independents tend to operate in the mature production areas dominated by stripper production.

Major Issues

Discharge of Produced Water and Oily Wastes to Ephemeral Streams

In the San Joaquin Valley, the State has long allowed discharge of oily high-chloride produced water to ephemeral streams. After discharge to ephemeral streams, the produced water is diverted into central sumps for disposal through evaporation and percolation. Infiltration of produced water into aquifers is assumed to occur, but official opinion on its potential for damage is divided. Some officials take the position that the aquifers are naturally brackish and thus have no beneficial use for agriculture or human consumption. A report by the Water Resources Control Board, however, suggests that produced water may percolate into useable ground-water structures.

For the purposes of this study conducted by Bean/Logan Consulting Geologists, ground water in the study area was categorized according to geotype and compared to produced water in sumps that came from production zones. Research was conducted on sumps in Cymric Valley, McKittrick Valley, Midway Valley, Elk Hills, Buena Vista Hills, and Buena Vista Valley production fields. While this recent research was not investigating ground-water damages per se, the study suggests obvious potential for damages relating to the ground water. The hydrogeologic analysis prepared for the California State Water Resources Control Board concludes that about 570,000 tons of salt from produced water were deposited in 1981 and that a total of 14.8 million tons have been deposited since 1900. The California Water Resources Board suspects that a portion of the salt has percolated into the ground water and has degraded it. In addition to suspected degradation of ground water, officers of the California Department of Fish and Game often find birds and animals entrapped in the oily deposits in the affected ephemeral streams. Exposure to the oily deposits often proves to be fatal to these birds and animals.[78] (CA 21)[79]

This is a permitted practice under current California regulations.

Aside from concerns over chronic degradation of ground water, this practice of discharge to ephemeral streams can cause damage to wildlife. The volume of wastes mixed with natural runoff sometimes exceeds the holding capacity of the ephemeral streams. The combined volume may then overflow the diversions to the sump areas and continue downstream, contaminating soil and endangering sensitive wildlife habitat. The oil and gas industry contends that it is rare for any wastes to pass the diversions set up to channel flow to the sumps, but the California Department of Fish and Game believes that it is a common occurrence.

Produced water from the Crocker Canyon area flows downstream to where it is diverted into Valley Waste Disposal's large unlined evaporation/percolation sumps for oil recovery (cooperatively operated by local oil producers). In one instance, discovery by California Fish and Game officials of a significant spill was made over a month after it occurred. According to the California State Water Quality Board, the incident was probably caused by heavy rainfall, as a consequence of which the volume of rain and waste exceeded the containment capacity of the disposal facility. The sumps became eroded, allowing oily waste to flow down the valley and into a wildlife habitat occupied by several endangered species including blunt-nosed leopard lizards, San Joaquin kit foxes, and giant kangaroo rats.

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78 API states that the California Regional Water Quality Board and EPA are presently deciding whether to promulgate additional permit requirements under the Clean Water Act and NPDES.

79 References for case cited: Lower Westside Water Quality Investigation Kern County, and Lower Westside Water Quality Investigation Kern County: Supplementary Report, Bean/Logan Consulting Geologists, 11/83; prepared for California State Water Resources Control Board. Westside Groundwater Study, Michael R. Rector, Inc., 11/83; prepared for Western Oil and Gas Association.

According to the State's report, there were 116 known wildlife losses including 11 giant kangaroo rats. The count of dead animals was estimated at only 20 percent of the actual number of animals destroyed because of the delay in finding the spill, allowing poisoned animals to leave the area before dying. Vegetation was covered with waste throughout the spill area. The California Department of Fish and Game does not believe this to be an isolated incident. The California Water Resources Control Board, during its investigation of the incident, noted "...deposits of older accumulated oil, thereby indicating that the same channel had been used for wastewater disposal conveyance in the past prior to the recent discharge. Cleanup activities conducted later revealed that buildup of older oil was significant." The companies implicated in this incident were fined $100,000 and were required to clean up the area. The companies denied responsibility for the discharge. (CA 08)[80]

This release was in violation of California regulations.

ALASKA

The Alaska zone includes Alaska and Hawaii. Hawaii has no oil or gas production. Alaska is second only to Texas in oil production.

Operations

Alaska's oil operations are divided into two entirely separate areas, the Kenai Peninsula (including the western shore of Cook Inlet) and the North Slope. Because of the areas' remoteness and harsh climate, operations in both areas are highly capital- and energy-intensive. For the purposes of damage case development, and indeed for most other types of analysis, operations in these two areas are distinct. Types of damages identified in the two areas have little in common.

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80 References for case cited: Report of Oil Spill in Buena Vista Valley, by Mike Glinzak, California Division of Oil and Gas (DOG), 3/6/86; map of site and photos accompany the report. Letters to Sun Exploration and Production Co. from DOG, 3/12 and 3/31/86. Newspaper articles in Bakersfield Californian, 3/8/86, 3/11/86, and undated. California Water Quality Control Board, Administrative Civil Liability Complaint #ACL-016, 8/8/86. California Water Quality Control Board, internal memoranda, Smith to Pfister concerning cleanup of site, 5/27/86; Smith to Nevins concerning description of damage and investigation, including map, 8/12/86. California Department of Fish and Game, Dead Endangered Species in a California Oil Spill, by Capt. E.A Simons and Lt. M. Akin, undated. Fact Sheets: Buena Vista Creek Oil Spill, Kern County, 3/7/86, and Mammals Occurring on Elk Hills and Buena Vista Hills, undated. Letter from Lt. Akin to EPA contractor, 2/24/87.

Activities on the Kenai Peninsula have been in progress since the late 1950s, and gas is the primary product. Production levels are modest as compared to those on the North Slope.

North Slope operations occur primarily in the Prudhoe Bay area, with some smaller fields located nearby. Oil is the primary product. Production has been under way since the trans-Alaska pipeline was completed in the mid 1970s. Much of the oil recovery in this area is now in the secondary phase, and enhanced recovery through water flooding is on the increase.

There were 100 wells drilled in the State in 1985, all of them on the North Slope. In 1985, one exploratory well was drilled in the National Petroleum Reserve - Alaska (NPRA) and two development wells were drilled on the Kenai Peninsula.

Types of Operators

There are no small, independent oil or gas operators in Alaska because of the high capital requirements for all activities in the region. Operators in the Kenai Peninsula include Union Oil of California and other major companies. Major producers on the North Slope are ARCO and Standard Alaska Production Company.

Major Issues

<u>Reserve Pits, North Slope</u>

Reserve pits on the North Slope are usually unlined and made of permeable native sands and gravels. Very large amounts of water flow in this area during breakup each spring in the phenomenon known as "sheet flow." Some of this water may unavoidably flow into and out of the reserve pits; however, the pits are designed to keep wastes in and keep

surface waters out. Discharge of excess liquids from the pits directly onto the tundra is permitted under regulations of the Alaska Department of Environmental Conservation (ADEC) if discharge standards are met. (See summary on State rules and regulations.)

Through the processes of breakup and discharge, ADEC estimates that 100 million gallons of supernatant are pumped onto the tundra and roadways each year,[81] potentially carrying with it reserve pit constituents such as chromium, barium, chlorides, and oil. Scientists who have studied the area believe this has the potential to lead to bioaccumulation of heavy metals and other contaminants in local wildlife, thus affecting the food chain. However, no published studies that demonstrate this possibility exist. Results from preliminary studies suggest that the possibility exists for adverse impact to Arctic wildlife because of discharge of reserve pit supernatant to the tundra:

> In 1983, a study of the effects of reserve pit discharges on water quality and the macroinvertebrate community of tundra ponds was undertaken by the U. S. Fish and Wildlife Service in the Prudhoe Bay oil production area of the North Slope. Discharge to the tundra ponds is a common disposal method for reserve pit fluid in this area. The study shows a clear difference in water quality and biological measures among reserve pits, ponds receiving discharges from reserve pits (receiving ponds), distant ponds affected by discharges through surface water flow, and control ponds not affected by discharges. Ponds directly receiving discharges had significantly greater concentrations of chromium, arsenic, cadmium, nickel, and barium than did control ponds, and distant ponds showed significantly higher levels of chromium than did control ponds. Chromium levels in reserve pits and in ponds adjacent to drill sites may have exceeded EPA chronic toxicity criteria for protection of aquatic life. (AK 06)[82]

These discharges were permitted by the State of Alaska. No NPDES permits have been issued for these discharges. New Alaska regulations have more stringent effluent limits.

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81 Statement by Larry Dietrick to Carla Greathouse.

82 References for case cited: The Effects of Prudhoe Bay Reserve Pit Fluids on the Water Quality and Macroinvertebrates of Tundra Ponds, by Robin L. West and Elaine Snyder-Conn, Fairbanks Fish and Wildlife Enhancement Office, U.S. Fish and Wildlife Service, Fairbanks, Alaska, 9/87.

In the summer of 1985, a field method was developed by the U. S. Fish and Wildlife Service to evaluate toxicity of reserve pit fluids discharged into tundra wetlands at Prudhoe Bay, Alaska. Results of the study document acute toxicity effects of reserve pit fluids on Daphnia. Acute toxicity in Daphnia was observed after 96 hours of exposure to liquid in five reserve pits. Daphnia exposed to liquid in receiving ponds also had significantly higher death/immobilization than did Daphnia exposed to liquid in control ponds after 96 hours. At Drill Site 1, after 96 hours, 100 percent of the Daphnia introduced to the reserve pit had been immobilized or were dead, as compared to a control pond which showed less than 5 percent immobilized or dead after 96 hours. At Drill Site 12, 80 percent of the Daphnia exposed to the reserve pit liquid were dead or immobilized after 96 hours and less than 1 percent of Daphnia exposed to the control pond were dead or immobilized.[83] (AK 07)[84]

In June 1985, five drill sites and three control sites were chosen for studying the effects of drilling fluids and their discharge on fish and waterfowl habitat on the North Slope of Alaska. Bioaccumulation analysis was done on fish tissue using water samples collected from the reserve pits. Fecundity and growth were reduced in daphnids exposed for 42 days to liquid composed of 2.5 percent and 25 percent drilling fluid from the selected drill sites. Bioaccumulation of barium, titanium, iron, copper, and molybdenum was documented in fish exposed to drilling fluids for as little as 96 hours. (AK 08)[85]

Erosion of reserve pits and subsequent discharge of reserve pit contents to the tundra constitute another potential environmental problem on the North Slope. If exploration drilling pits are not closed out at the end of a drilling season, they may breach during "breakup." Reserve pit contaminants are then released directly to the tundra. (As described in Chapter III, production reserve pits are different from exploration reserve pits. Production reserve pits are designed to last for as long as 20 years.) A reserve pit wall may be poorly constructed or suffer structural damage during use; the wall may be breached by the hydrostatic head on the walls due to accumulation of precipitation and produced fluids. New exploration reserve pits are generally constructed below-grade. Flow of gravel during a pit breach can choke or cut off tundra streams, severely damaging or eliminating aquatic habitat.

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83 API comments in the Docket pertain to AK 07. API discusses the relevance of the Daphnia study to the damage cases.

84 References for case cited: An In Situ Acute Toxicity Test with Daphnia: A Promising Screening Tool for Field Biologists? by Elaine Snyder-Conn, U.S. Fish and Wildlife Service, Fish and Wildlife Enhancement, Fairbanks, Alaska, 1985.

85 References for case cited: Effects of Oil Drilling Fluids and Their Discharge on Fish and Waterfowl Habitat in Alaska, U.S. Fish and Wildlife Service, Columbia National Fishery Research Laboratory, Jackson Field Station, Jackson, Wyoming, February 1986.

The Awuna Test Well No. 1, which is 11,200 feet deep, is in the National Petroleum Reserve in Alaska (NPRA) and was a site selected for cleanup of the NPRA by the U.S. Geological Survey (USGS) in 1984. The site is in the northern foothills of the Brooks Range. The well was spud on February 29, 1980, and operations were completed on April 20,1981. A side of the reserve pit berm washed out into the tundra during spring breakup, allowing reserve pit fluid to flow onto the tundra. As documented by the USGS cleanup team, high levels of chromium, oil, and grease have leached into the soil downgradient from the pit. Chromium was found at 2.2 to 3.0 mg/kg dry weight. The high levels of oil and grease may be from the use of Arctic Pack (85 percent diesel fuel) at the well over the winter of 1980. The cleanup team noted that the downslope soils were discolored and putrefied, particularly in the upper layers. The pad is located in a runoff area allowing for erosion of pad and pit into surrounding tundra. A vegetation kill area caused by reserve pit fluid exposure is approximately equal to half an acre. Areas of the drill pad may remain barren for many years because of contamination of soil with salt and hydrocarbons. The well site is in a caribou calving area.[86] (AK 12)[87]

This type of reserve pit construction is no longer permitted under current Alaska regulations.

Waste Disposal on the North Slope

Inspection of oil and gas activities and enforcement of State regulations on the North Slope is difficult, as illustrated by the following case:

North Slope Salvage, Inc. (NSSI) operated a salvage business in Prudhoe Bay during 1982 and 1983. During this time, NSSI accepted delivery of various discarded materials from oil production companies on the North Slope, including more than 14,000 fifty-five gallon drums, 900 of which were full or held more than residual amounts of oils and chemicals used in the development and recovery of oil. The drums were stockpiled and managed by NSSI in a manner that allowed the discharge of hazardous substances. While the NSSI site may have stored chemicals and wastes from other operations that supported oil and gas exploration and production (e.g., vehicle maintenance materials), such storage would have constituted a very small percentage of NSSI's total inventory.

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86 API states that exploratory reserve pits must now be closed 1 year after cessation of drilling operations. EPA notes that it is important to distinguish between exploratory and production reserve pits. Production reserve pits are permanent structures that remain open as long as the well or group of wells is producing. This may be as long as 20 years.

87 References for case cited: Final Wellsite Cleanup on National Petroleum Reserve - Alaska, USGS, July 1986.

The situation was discovered by the Alaska Department of Environmental Conservation (ADEC) in June 1983. At this time, the State of Alaska requested Federal enforcement, but Federal action was never taken. An inadequate cleanup effort was mounted by NSSI after confrontation by ADEC. To preclude further discharges of hazardous substances, ARCO and Sohio paid for the cleanup because they were the primary contributors to the site. Cleanup was completed on August 5, 1983, after 58,000 gallons of chemicals and water were recovered. It is unknown how much of the hazardous substances was carried into the tundra. The discharge consisted of oil and a variety of organic substances known to be toxic, carcinogenic, mutagenic, or suspected of being carcinogenic or mutagenic.[88] (AK 10)[89]

Disposal of Drilling Wastes, Kenai Peninsula

Disposal of drilling wastes is the principal practice leading to potential environmental degradation on the Kenai Peninsula. The following cases involve centralized facilities, both commercial and privately run, for disposal of drilling wastes:

Operators of the Sterling Special Waste Site have had a long history of substandard monitoring, having failed during 1977 and 1978 to carry out any well sampling and otherwise having performed only irregular sampling. This was in violation of ADEC permit requirements to perform quarterly reports of water quality samples from the monitoring wells. An internal ADEC memo (L.G. Elphic to R.T. Williams, 2/25/76) noted "...we must not forget...that this is the State's first sanctioned hazardous waste site and as such must receive close observation during its initial operating period."[90]

A permit for the site was reissued by ADEC in 1979 despite knowledge by ADEC of lack of effective ground-water monitoring. In July of 1980, ADEC Engineer R. Williams visited the site and filed a report noting that the "...operation appears completely out of control." Monitoring well samples were analyzed by ADEC at this time and were found to be in excess of drinking water standards for iron, lead, cadmium, copper, zinc, arsenic, phenol, and oil and grease. One private water well in the vacinity showed 0.4 ppb 1,1,1-trichloroethane. The Sterling School well showed 2.1 g/L mercury. (Subsequent tests show mercury concentration below detection limits--0.001 mg/kg.) Both contamination incidents are alleged to be caused by the Sterling

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88 Alaska Department of Environmental Conservation (ADEC) states that this case "...<u>is</u> an example of how the oil industry inappropriately considered the limits of the exemption [under RCRA Section 3001]."

89 References for case cited: Report on the Occurrence, Discovery, and Cleanup of an Oil and Hazardous Substances Discharge at Lease Tract 57, Prudhoe Bay, Alaska, by Jeff Mach - ADEC, 1984. Letter to Dan Derkics, EPA, from Stan Hungerford, ADEC, 8/4/87.

90 The term "hazardous waste site" as used in this memo does not refer to a "RCRA Subtitle C hazardous waste site."

Special Waste Site. Allegations are unconfirmed by the ADEC. (AK 03)[91]

Practices at the Sterling site were in violation of the permit.

This case involves a 45-acre gravel pit on Poppy Lane on the Kenai Peninsula used since the 1970s for disposal of wastes associated with gas development. The gravel pit contains barrels of unidentified wastes, drilling muds, gas condensate, gas condensate-contaminated peat, abandoned equipment, and soil contaminated with diesel and chemicals. The property belongs to Union Oil Co., which bought it around 1968. Dumping of wastes in this area is illegal; reports of last observed dumping were in October 1985, as witnessed by residents in the area. In this case, there has been demonstrated contamination of adjacent water wells with organic compounds related to gas condensate (ADEC laboratory reports from October 1986 and earlier). Alleged health effects on residents of neighboring properties include nausea, diarrhea, rashes, and elevated levels of metals (chromium, copper) in blood in two residents. Property values have been effectively reduced to zero for residential resale. A fire on the site on July 8, 1981, was attributed to combustion of petroleum-related products, and the fire department was unable to extinguish it. The fire was allegedly set by people illegally disposing of wastes in the pit. Fumes from organic liquids are noticeable in the breathing zone onsite. UNOCAL has been directed on several occasions to remove gas condensate in wastes from the site. Since June 19, 1972, disposal of wastes regulated as solid wastes has been illegal at this site. The case has been actively under review by the State since 1981. (AK 01)[92]

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91 References for case cited: Dames and Moore well monitoring report, showing elevated metals referenced above, October 1976. Dowling Rice & Associates monitoring results, 1/15/80, and Mar Enterprises monitoring results, September 1980, provided by Walt Pederson, showing elevated levels of metals, oil, and grease in ground water. Detailed letter from Eric Meyers to Glen Aikens, Deputy Commissioner, ADEC, recounting permit history of site and failure to conduct proper monitoring, 1/22/82. Testimony and transcripts from Walt Pederson on public forums complaining about damage to drinking water and mismanagement of site. Transcripts of waste logs of site from 9/1/79 to 8/20/84, indicating only 264,436 bbl of muds received, during a period that should have generated much more waste. Letter from Howard Keiser to Union Oil, 12/7/81, indicating that "...drilling mud is being disposed of by methods other than at the Sterling Special Waste Site and by methods that could possibly cause contamination of the ground water."

92 References for case cited: Photos showing illegal dumping in progress. Field investigations. State of Alaska Individual Fire Report on "petroleum dump," 7/12/81. File memo on site visit by Howard Keiser, ADEC Environmental Field Officer, in response to a complaint by State Forestry Officer, 7/21/81. Memo from Howard Keiser to Bob Martin on his objections to granting a permit to Union Oil for use of site as disposal site on basis of impairment of wildlife resources, 7/28/83. Letter, ADEC to Union Oil, objecting to lack of cleanup of site despite notification by ADEC on 10/3/84. Analytical reports by ADEC indicating gas condensate contamination on site, 8/14/84. EPA Potential Hazardous Waste Site Identification, indicating continued dumping as of 8/10/85. Citizens' complaint records. Blood test indicating elevated chromium for neighboring resident Jessica Black, 1/16/85. Letter to Mike Lucky of ADEC from Union Oil confirming cleanup steps, 2/12/85. Memo by Carl Reller, ADEC ecologist, indicating presence of significant toxics on site, 8/14/85. Minutes of Waste Disposal Commission meeting, 2/10/85. ADEC analytic reports indicating gas condensate at site, 10/10/85. Letters from four different real estate firms in area confirming inability to sell residential property in Poppy Lane area. Letter from Bill Lamoreaux, ADEC, to J. Black and R. Sizemore referencing high selenium/chromium in the ground water in the area. Miscellaneous technical documents. EPA Potential Hazardous Waste Site Preliminary Assessment, 2/12/87.

These activities are illegal under current Alaska regulations.

MISCELLANEOUS ISSUES

Improperly Abandoned and Improperly Plugged Wells

Degradation of ground water from improperly plugged and unplugged wells is known to occur in Kansas, Texas, and Louisiana. Improperly plugged and unplugged wells enable native brine to migrate up the wellbore and into freshwater aquifers. The damage sustained can be extensive.

Problems also occur when unidentified improperly plugged wells are present in areas being developed as secondary recovery projects. After the formation has been pressurized for secondary recovery, native brine can migrate up unplugged or improperly plugged wells, potentially causing extensive ground-water contamination with chlorides.

> In 1961, Gulf and its predecessors began secondary recovery operations in the East Gladys Unit in Sedgwick County, Kansas. During secondary recovery, water is pumped into a target formation at high pressure, enhancing oil production. This pumping of water pressurizes the formation, which can at times result in brines being forced up to the surface through unplugged or improperly plugged abandoned wells. When Gulf began their secondary recovery in this area, it was with the knowledge that a number of abandoned wells existed and could lead to escape of salt water into fresh ground water.
>
> Gerald Blood alleged that three improperly plugged wells in proximity to the Gladys unit were the source of fresh ground-water contamination on his property. Mr. Blood runs a peach orchard in the area. Apparently native brine had migrated from the nearby abandoned wells into the fresh ground water from which Mr. Blood draws water for domestic and irrigation purposes. Contamination of irrigation wells was first noted by Mr. Blood when, in 1970, one of his truck gardens was killed by irrigation with salty water. Brine migration contaminated two more irrigation wells in the mid-1970s. By 1980, brine had contaminated the irrigation wells used to irrigate a whole section of Mr. Blood's land. By this time, adjacent landowners also had contaminated wells. Mr. Blood lost a number of peach trees as a result of the contamination of his irrigation well; he also lost the use of his domestic well.

The Bloods sued Gulf Oil in civil court for damages sustained by their farm from chloride contamination of their irrigation and residential wells. The Bloods won their case and were awarded an undisclosed amount of money.[93] (KS 14)[94]

Current UIC regulations prohibit contamination of groundwater.

The potential for environmental damage through ground-water degradation is high, given the thousands of wells abandoned throughout the country prior to any State regulatory plugging requirements.

In West Texas, thousands of oil and gas wells have been drilled over the last several decades, many of which were never properly plugged. There exists in the subsurface of this area a geologic formation known as the Coleman Junction, which contains extremely salty native brine and possesses natural artesian properties. Since this formation is relatively shallow, most oil and gas wells penetrate this formation. If an abandoned well is not properly plugged, the brine contained in the Coleman Junction is under enough natural pressure to rise through the improperly plugged well and to the surface.

According to scientific data developed over several years, and presented by Mr. Ralph Hoelscher, the ground water in and around San Angelo, Texas, has been severely degraded by this seepage of native brine, and much of the agricultural land has absorbed enough salt as to be nonproductive. This situation has created a hardship for farmers in the area. The Texas Railroad Commission states that soil and ground water are contaminated with chlorides because of terracing and fertilizing of the land. According to Mr. Hoelscher, a long-time farmer in the area, little or no fertilizer is used in local agriculture. (TX 11)[95]

Improper abandonment of oil and gas wells is prohibited in the State of Texas.

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93 API states that damage in this case was brought about by "old injection practices."

94 References for case cited: U.S. District Court for the district of Kansas, Memorandum and Order, Blood vs. Gulf; Response to Defendants' Statement of Uncontroverted Facts; and Memorandum in Opposition to Motion for Summary Judgment. Means Laboratories, Inc., water sample results. Department of Health, District Office #14, water samples results. Extensive miscellaneous memoranda, letters, analysis.

95 References for case cited: Water analysis of Ralph Hoelscher's domestic well. Soil Salinity Analysis, Texas Agricultural Extension Service - The Texas A&M University System, Soil Testing Laboratory, Lubbock, Texas 79401. Photographs. Conversation with Wayne Farrell, San Angelo Health Department. Conversation with Ralph Hoelscher, resident and farmer.

CHAPTER V

RISK MODELING

INTRODUCTION

This chapter summarizes the methods and results of a risk analysis of certain wastes associated with the onshore exploration, development, and production of crude oil and natural gas. The risk analysis relies heavily on the information developed by EPA on the types, amounts, and characteristics of wastes generated (summarized in Chapter II) and on waste management practices (summarized in Chapter III). In addition, this quantitative modeling analysis was intended to complement EPA's damage case assessment (Chapter IV). Because the scope of the model effort was limited, some of the types of damage cases reported in Chapter IV are not addressed here. On the other hand, the risk modeling of ground-water pathways covers the potential for certain more subtle or long-term risks that might not be evidenced in the contemporary damage case files. The methods and results of the risk analysis are documented in detail in a supporting EPA technical report (USEPA 1987a).

EPA's risk modeling study estimated releases of contaminants from selected oil and gas wastes into ground and surface waters, modeled fate and transport of these contaminants, and estimated potential exposures, health risks, and environmental impacts over a 200-year modeling period. The study was not designed to estimate absolute levels of national or regional risks, but rather to investigate and compare potential risks under a wide variety of conditions.

Objectives

The main objectives of the risk analysis were to (1) characterize and classify the major risk-influencing factors (e.g., waste types, waste

management practices, environmental settings) associated with current operations at oil and gas facilities;[1] (2) estimate distributions of major risk-influencing factors across the population of oil and gas facilities within various geographic zones; (3) evaluate these factors in terms of their relative effect on risks; and (4) develop, for different geographic zones of the U.S., initial quantitative estimates of the possible range of baseline health and environmental risks for the variety of existing conditions.

Scope and Limitations

The major portion of this risk study involved a predictive quantitative modeling analysis focusing on large-volume exempt wastes managed according to generally prevailing industry practices. EPA also examined (but did not attempt quantitative assessment of) the potential effects of oil and gas wastes on the North Slope of Alaska, and reviewed the locations of oil and gas activities relative to certain environments of special interest, including endangered species habitats, wetlands, and public lands.

Specifically, the quantitative risk modeling analysis estimated long-term human health and environmental risks associated with the disposal of drilling wastes in onsite reserve pits, the deep well injection of produced water, and the direct discharge of produced water from stripper wells to surface waters. These wastes and waste management practices encompass the major waste streams and the most common management practices within the scope of this report, but they are not necessarily those giving rise to the most severe or largest number of damage cases of the types presented in Chapter IV. For risk modeling purposes, EPA generally assumed full compliance with applicable current State and

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1 References in this chapter to oil and gas facilities, sites, or activities refer to exploration, development, and production operations.

Federal regulations for the practices studied. Risks were not modeled for a wide variety of conditions or situations, either permitted or illegal, that could give rise to damage incidents, such as waste spills, land application of pit or water wastes, discharge of produced salt water to evaporation/percolation pits, or migration of injected wastes through unplugged boreholes.

In this study, EPA analyzed the possible effects of selected waste streams and management practices by estimating risks for <u>model scenarios</u>. Model scenarios are defined as hypothetical (but realistic) combinations of variables representing waste streams, management practices, and environmental settings at oil and gas facilities. The scenarios used in this study were, to the extent possible, based on the range of conditions that exist at actual sites across the U.S. EPA developed and analyzed more than 3,000 model scenarios as part of this analysis.

EPA also estimated the geographic and waste practice frequencies of occurrence of the model scenarios to account for how well they represent actual industry conditions and to account for important variations in oil and gas operations across different geographic zones of the U.S.[2] These frequencies were used to weight the model results, that is, to account for the fact that some scenarios represent more sites than others. However, even the weighted risk estimates should not be interpreted as absolute risks for real facilities because certain major risk-influencing factors were not modeled as variables and because the frequency of occurrence of failure/release modes and concentrations of toxic constituents were not available.

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2 The 12 zones used in the risk assessment are identical to the zones used as part of EPA's waste sampling and analysis study (see Chapter II), with one exception: zone 11 (Alaska) was divided into zone 11A representing the North Slope and zone 11B representing the Cook Inlet-Kenai Peninsula area.

A principal limitation of the risk analysis is that EPA had only a relatively small sample set of waste constituent concentration data for the waste streams under study. As a result, the Agency was unable to construct regional estimates of toxic constituent concentrations or a national frequency distribution of concentrations that could be directly related to other key geophysical or waste management variables in the study. Partly because of this data limitation, all model scenarios defined for this study were analyzed under two different sets of assumptions: a "best-estimate"[3] set of assumptions and a "conservative" set of assumptions. The best-estimate and conservative sets of assumptions are distinguished by different waste constituent concentrations, different timing for releases of drilling waste and produced water, and, in some cases, different release rates (see the later sections on model scenarios and model procedures for more detail). The best-estimate assumptions represent a set of conditions which, in EPA's judgment, best characterize the industry as a whole, while the conservative assumptions define higher-risk (but not worst-case) conditions. It is important to clarify that the best-estimate and conservative assumptions are not necessarily based on a comprehensive statistical analysis of the frequency of occurrence or absolute range of conditions that exist across the industry; instead, they reflect EPA's best judgment of a reasonable range of conditions based on available data analyzed for this study.

Another major limitation of the study is the general absence of empirical information on the frequency, extent, and duration of waste releases from the oil and gas field management practices under consideration. As described below, this study used available engineering judgments regarding the nature of a variety of failure/release mechanisms for waste pits and injection wells, but no assumptions were made

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3 As used here, the term best estimate is different from the statistical concept of maximum likelihood (i.e., best) estimate.

regarding the relative frequency or probability of occurrence of such failures.

Although EPA believes that the scenarios analyzed are realistic and representative, the risk modeling for both sets of scenarios incorporated certain assumptions that tend to overestimate risk values. For example, for the health risk estimates it was assumed that individuals ingest untreated contaminated water over a lifetime, even if contaminant concentrations were to exceed concentrations at which an odor or taste is detectable. In addition, ingested concentrations were assumed to equal the estimated center line (i.e., highest) concentration in the contaminant plume.

Other features of the study tend to result in underestimation of risk. For example, the analysis focuses on risks associated with drilling or production at single oil or gas wells, rather than on the risks associated with multiple wells clustered in a field, which could result in greater risks and impacts because of overlapping effects. Also, the analysis does not account for natural or other source background levels of chemical constituents which, when combined with the contamination levels from oil and gas activities, could result in increased risk levels.

QUANTITATIVE RISK ASSESSMENT METHODOLOGY

EPA conducted the quantitative risk assessment through a four-step process (see Figure V-1). The first three steps--collection of input data, specification of model scenarios, and development of modeling procedures--are described in the following subsections. The last step, estimation of effects, is described in subsequent sections of this chapter that address the quantitative modeling results.

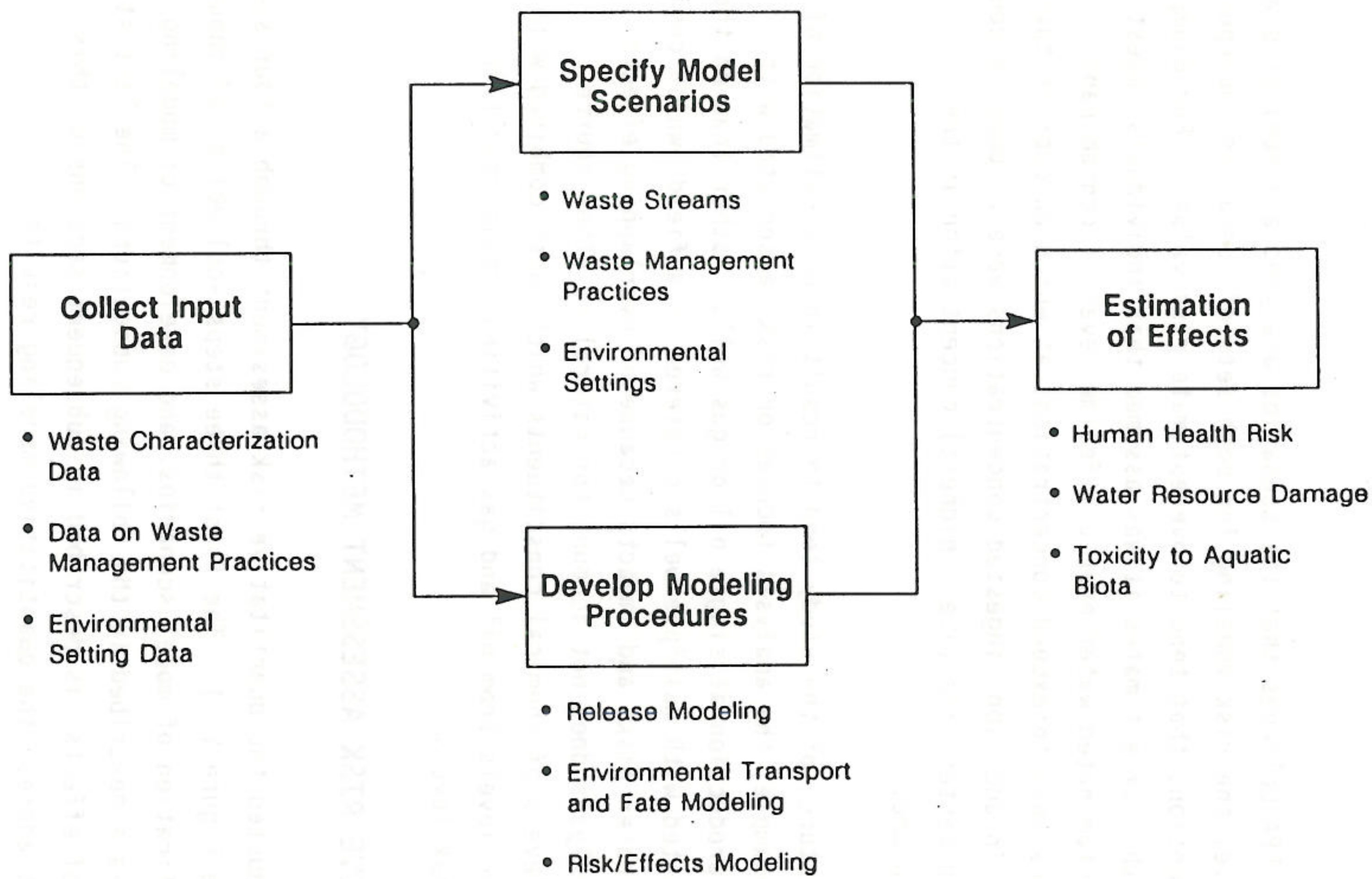

Figure V-1 Overview of Quantitative Risk Assessment Methodology

Input Data

EPA collected three main categories of input data for the quantitative modeling: data on waste volumes and constituents, waste management practices, and environmental settings. Data on waste volumes were obtained from EPA's own research on sources and volumes of wastes, supplemented by the results of a survey of oil and gas facilities conducted by the American Petroleum Institute (API) (see Chapter II). Data on waste constituents were obtained from EPA's waste stream chemical analysis study. The results of EPA's research on current waste management practices, supplemented by API's studies (see Chapter III), were the basis for defining necessary input parameters concerning waste management practices. Data needed to characterize environmental settings were obtained from an analysis of conditions at 266 actual drilling and production locations sampled from areas with high levels of oil and gas activity (see USEPA 1987a, Chapter 3, for more detail on the sample selection and analytical methods).

Model Scenarios

The model scenarios in this analysis are unique combinations of the variables used to define waste streams, waste management practices, and environmental settings at oil and gas facilities. Although the model scenarios are hypothetical, they were designed to be:

- Representative of actual industry conditions (they were developed using actual industry data, to the extent available);
- Broad in scope, covering prevalent industry characteristics but not necessarily all sets of conditions that occur in the industry; and
- Sensitive to major differences in environmental conditions (such as rainfall, depth to ground water, and ground-water flow rate) across various geographic zones of the U.S.

As illustrated in Figure V-2, EPA decided to focus the quantitative analysis on the human health and environmental risks associated with three types of environmental releases: leaching of drilling waste chemical constituents from onsite reserve pits to ground water below the pits (drilling sites); release of produced water chemical constituents from underground injection wells to surface aquifers[4] (production sites); and direct discharge of produced water chemical constituents to streams and rivers (stripper well production sites).

Chemical Constituents

EPA used its waste sampling and analysis data (described in Chapter II) to characterize drilling wastes and produced water for quantitative risk modeling. Based on the available data, EPA could not develop separate waste stream characterizations for various geographic zones; one set of waste characteristics was used to represent the nation. The model drilling waste represents only water-based drilling muds (not oil-based muds or wastes from air drilling), which are by far the most prevalent drilling mud type. Also, the model drilling waste does not represent one specific process waste, but rather the combined wastes associated with well drilling that generally are disposed of in reserve pits.

For both drilling wastes and produced water, EPA used a systematic methodology to select the chemical constituents of waste streams likely to dominate risk estimates (see USEPA 1987a, Chapter 3, for a detailed description of this methodology). The major factors considered in the chemical selection process were (1) median and maximum concentrations in

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4 For the purpose of this report, a surface aquifer is defined as the geologic unit nearest the land surface that transmits sufficient quantities of ground water to be used as a source of drinking water. It is distinguished from aquifers at greater depths, which may be the injection zone for an underground injection well or are too deep to be generally used as a drinking water source.

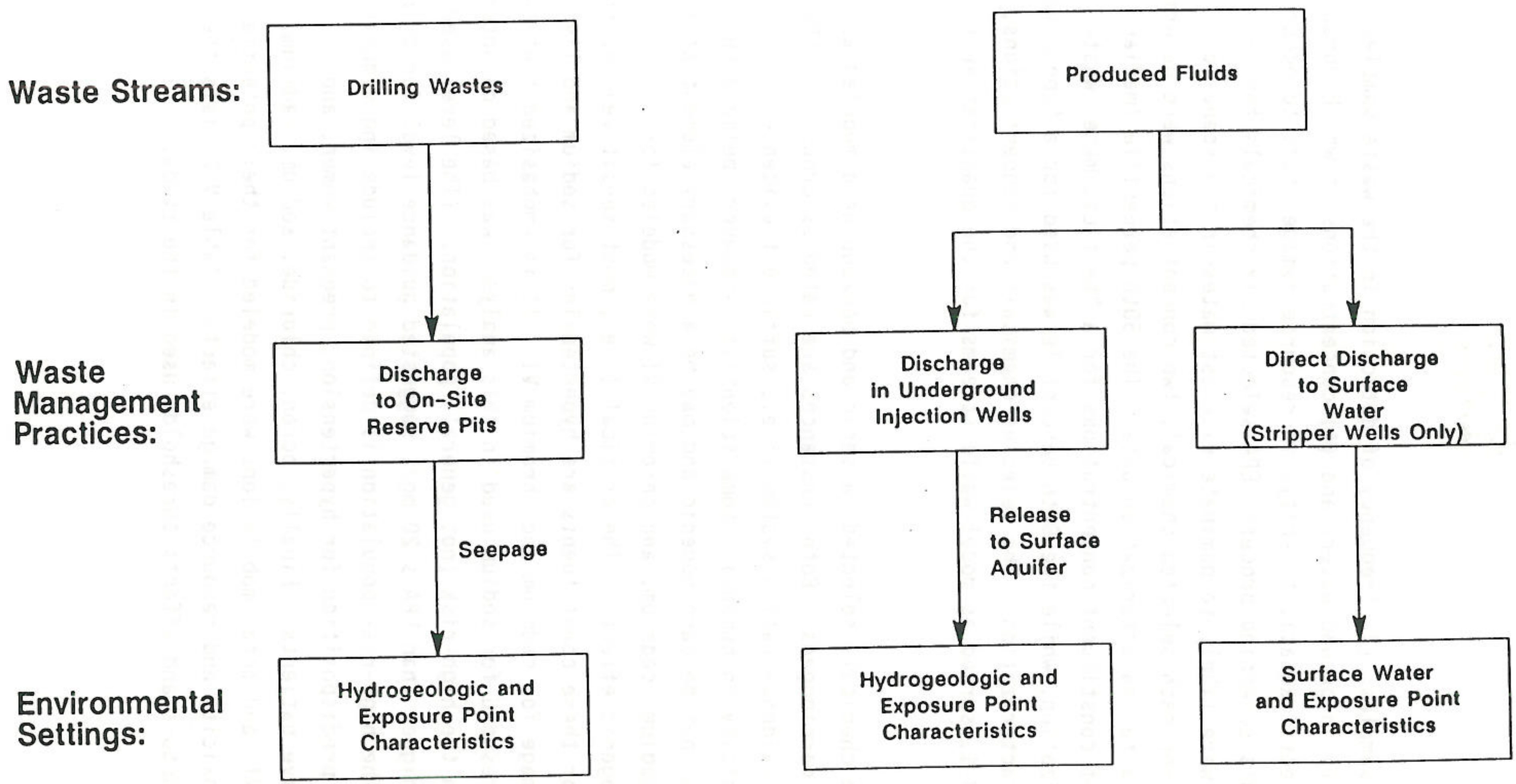

Figure V-2 Overview of Modeling Scenarios Considered in the Quantitative Risk Assessment

the waste samples; (2) frequency of detection in the waste samples; (3) mobility in ground water; and (4) concentrations at which human health effects, aquatic toxicity, or resource damage start to occur. Through this screening process, EPA selected six chemicals for each waste type that were likely to dominate risk estimates in the scenarios modeled. For each selected chemical, two concentrations were determined from the waste characterization data. The 50th percentile (median) was used to set constituent concentrations for a "best-estimate" waste characterization, while the 90th percentile was used for a "conservative" waste characterization. The selected chemicals and concentrations, shown in Table V-1, served as model waste streams for the quantitative risk analysis.

Of the chemicals selected, arsenic and benzene were modeled as potential carcinogens. Both substances are rated as Group A in EPA's weight-of-evidence rating system (i.e., sufficient evidence of carcinogenicity in humans). Some scientists, however, believe that arsenic may not be carcinogenic and may be a necessary element at low levels. Sodium, cadmium, and chromium VI were modeled for noncarcinogenic effects. The critical (i.e., most sensitive) health effects for these constituents are hypertension for sodium and liver and kidney damage for cadmium and chromium VI. It is emphasized that the effect threshold for sodium used in this analysis was based on potential effects in the high-risk (not general) population. (The level used is slightly higher than EPA's 20 mg/L suggested guidance level for drinking water.) The high-risk population is defined to include individuals with a genetic predisposition for hypertension, pregnant women, and hypertensive patients. Finally, boron, chloride, sodium, cadmium, chromium VI, and total mobile ions were modeled for their potential aquatic toxicity and resource damage effects. Table V-2 lists the cancer potency factors and effects thresholds used in the study.

Table V-1 Model Constituents and Concentrations[a]

Produced water constituents	Concentrations Median (mg/L)	Upper 90% (mg/L)
Arsenic	0.02	1.7
Benzene	0.47	2.9
Boron	9.9	120
Sodium	9,400	67,000
Chloride	7,300	35,000
Mobile ions[b]	23,000	110,000

Drilling waste (water-based) constituents	Pit liquids Median (mg/L)	Pit liquids Upper 90% (mg/L)	Pit solids/TCLP[c] Median (mg/L)	Pit solids/TCLP[c] Upper 90% (mg/L)	Pit solids/direct Median (mg/kg)	Pit solids/direct Upper 90% (mg/kg)
Arsenic	0.0	0.16	0.0	0.002[d]	0.0	0.010
Cadmium	0.056	1.4	0.011	0.29	2.0	5.4
Sodium	6,700	44,000	1,200[e]	4,400[e]	8,500	59,000
Chloride	3,500	39,000	2,000[f]	11,000[f]	17,000	88,000
Chromium VI	0.43	290	0	0.78	22	190
Mobile ions[b]	17,000	95,000	4,000	16,000	100,000	250,000

[a]The median constituent concentrations from the relevant samples in the EPA waste sampling/analysis study were used for a "best-estimate" waste characterization, and the 90th percentile concentrations were used for a "conservative" waste characterization (data source: USEPA 1987b).

[b]Mobile ions include chloride, sodium, potassium, calcium, magnesium, and sulfate.

[c]TCLP = toxicity characteristic leaching procedure.

[d]Upper 90th percentile arsenic values estimated based on detection limit.

[e]Preliminary examinations indicate that the sodium TCLP values may overestimate the actual leachable sodium concentrations in reserve pit samples. The accuracy of these concentrations is the subject of an ongoing evaluation.

[f]Chloride TCLP values are estimated based on sodium data.

Table V-2 Toxicity Parameters and Effects Thresholds[a]

Model constituent	Cancer potency factor $(mg/kd\text{-}d)^{-1}$	Human noncancer threshold (mg/kg-d)	Aquatic toxicity threshold (mg/L)	Resource damage threshold (mg/L)
Benzene	0.052	NA	NA[b]	NA
Arsenic	15	NA	NA	NA
Sodium	NA	0.66	83.4	NA
Cadmium	NA[c]	0.00029	0.00066	NA
Chromium VI	NA[c]	0.005	0.011	NA
Chloride	NA	NA	NA	250
Boron	NA	NA	NA	1
Total mobile ions[d]	NA	NA	NA	335[e] 500[f]

[a]See USEPA 1987a for detailed description and documentation.

[b]NA = not applicable; indicates that an effect type was not modeled for a specific chemical.

[c]Not considered carcinogenic by the oral exposure route.

[d]Represents total mass of ions mobile in ground water.

[e]For surface water only (assumes a background level of 65 mg/L and a threshold limit of 400 mg/L).

[f]For ground water only.

The chemicals selected for risk modeling differ from the constituents of potential concern identified in Chapter II for at least three important reasons. First, the analysis in Chapter II considers the hazards of the waste stream itself but, unlike the selection process used for this risk analysis, does not consider the potential for waste constituents to migrate through ground water and result in exposures at distant locations. Second, certain constituents were selected based on their potential to cause adverse environmental (as opposed to human health) effects, while the analysis in Chapter II considers only human health effects. Third, frequency of detection was considered in selecting constituents for the risk modeling but was not considered in the Chapter II analysis.

Waste Management Practices

Three general waste management practices were considered in this study: onsite reserve pits for drilling waste; underground injection wells for produced water; and direct discharge of produced water to rivers and streams (for stripper wells only).[5] EPA considered the underground injection of produced water in disposal wells and waterflooding wells.[6] The design characteristics and parameter values modeled for the different waste management practices are presented in Tables V-3 and V-4. These values were developed from an evaluation of EPA's and API's waste volume data (see Chapter II) and waste management practice survey results (see Chapter III) for the nation as a whole.

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5 At present, there are no Federal effluent guidelines for stripper wells (i.e., oil wells producing less than ten barrels of crude oil per day), and, under Federal law, these wells are allowed to discharge directly to surface waters subject to certain restrictions. Most other onshore oil and gas facilities are subject to the Federal zero-discharge requirement.

6 Waterflooding is a secondary recovery method in which treated fresh water, seawater, or produced water is injected into a petroleum-bearing formation to help maintain pressure and to displace a portion of the remaining crude oil toward production wells. Injection wells used for waterflooding may have different designs, operating practices, and economic considerations than those of disposal wells, which are used simply to dispose of unwanted fluid underground.

Table V-3 Drilling Pit Waste (Water-Based) Management Practices

Onsite pit size	Waste amount[a] (barrels)	Disposal practice	Pit dimensions(m) L	W	D
Large	26,000	Reserve pit-unlined	59	47	2.3[b]
		Reserve pit-lined, capped			
Medium	5,900	Reserve pit-unlined	32	25	2.0[b]
		Reserve pit-lined, capped			
Small	1,650	Reserve pit-unlined	17	14	1.9[b]
		Reserve pit-lined, capped			

[a]Per well drilled (includes solids and liquids).

[b]Waste depths for large, medium, and small pits were 1.5, 1.2, and 1.1 meters, respectively.

Table V-6 Definition of Best Estimate and Conservative Release Assumptions

Release source	Release assumption	Constituent concentration in waste[a]	Failure/release timing	Release volume
Unlined Pits	Best-estimate	50th % (median)	Release begins in year 1	Calculated by release equations
	Conservative	90th %	Release begins in year 1	Calculated by release equations (same as best-estimate)
Lined Pits	Best-estimate	50th %	Liner failure begins in year 25	Calculated by release equations
	Conservative	90th %	Liner failure begins in year 5	Calculated by release equations (same as best-estimate)
Injection Wells/ Casing Failure	Best-estimate	50th %	One year release in year 1 for waterflood wells; constant annual releases during years 11-13 for disposal wells	0.2-96 bbl/d for waterflood wells; 0.05-38 bbl/d for disposal wells
	Conservative	90th %	Constant annual releases during years 11-15 for waterflood and disposal wells	Same as best-estimate
Injection Wells/ Grout Seal Failure	Best-estimate	50th %	Constant annual releases during years 11-15 for waterflood and disposal wells	0.00025-0.0025 bbl/d for waterflood wells; 0.00025-0.0075 bbl/d for disposal wells
	Conservative	90th %	Constant annual releases during years 1-20 for waterflood and disposal wells (immediate failure, no detection)	0.05-0.5 bbl/d for waterflood wells; 0.05-1.5 bbl/d for disposal wells

[a]See Table V-1.

the same layers considered during the active period. For unlined pits, release was assumed to begin immediately at the start of the modeling period. For lined pits, failure (i.e., increase in hydraulic conductivity of the liner) was assumed to occur either 5 or 25 years after the start of the modeling period. It was assumed that any liquids remaining in unlined reserve pits at the time of closure would be land applied adjacent to the pit. Liquids remaining in lined pits were assumed to be disposed offsite.

For modeling releases to surface aquifers from Class II injection wells, a 20-year injection well operating period was assumed, and two failure mechanisms were studied: (1) failure of the well casing (e.g., a corrosion hole) and (2) failure of the grout seal separating the injection zone from the surface aquifer. At this time, the Agency lacks the data necessary to estimate the probability of casing or grout seal failures occurring. A well casing failure assumes that injected fluids are exiting the well through a hole in the casing protecting the surface aquifer. In most cases, at least two strings of casing protect the surface aquifer and, in those cases, a release to this aquifer would be highly unlikely. The Agency has made exhaustive investigations of Class I well (i.e., hazardous waste disposal well) failures and has found no evidence of release of injected fluids through two strings of casing. However, the Agency is aware that some Class II wells were constructed with only one string of casing; therefore, the scenarios modeled fall within the realm of possible failures. Since integrity of the casing must be tested every 5 years under current EPA guidelines (more frequently by some States), EPA assumed for the conservative scenarios that a release would begin on the first day after the test and would last until the next test (i.e., 5 years). For the best-estimate scenarios, EPA assumed that the release lasted 1 year (the minimum feasible modeling period) in the case of waterflood wells and 3 years in the case of disposal wells, on the supposition that shorter release durations would be more likely for

waterflooding where injection flow rates and volumes are important economic considerations for the operation. EPA also assumed here that the release flow from a failed well would remain constant over the duration of the failure. This simplifying assumption is more likely to hold in low-pressure wells than in the high-pressure wells more typical of waterflooding operations. In high-pressure wells the high flow rate would likely enlarge the casing holes more rapidly, resulting in more injection fluid escaping into the wrong horizon and a noticeable drop of pressure in the reservoir.

For the grout seal type of failure, EPA estimated for conservative modeling purposes that the failure could last for 20 years (i.e., as long as the well operates). This is not an unreasonable worst-case assumption because the current regulations allow the use of cementing records to determine adequacy of the cement job, rather than actual testing through the use of logs. If the cementing records were flawed at the outset, a cementing failure might remain undetected. As part of its review of the Underground Injection Control (UIC) regulations, the Agency is considering requiring more reliable testing of the cementing of wells, which would considerably lessen the likelihood of such scenarios. For an alternative best-estimate scenario, the Agency assumed a 5-year duration of failure as a more typical possibility.

Because of a lack of both data and adequate modeling methods, other potentially important migration pathways by which underground injection of waste could contaminate surface aquifers (e.g., upward contaminant migration from the injection zone through fractures/faults in confining layers or abandoned boreholes) were not modeled.

Chemical transport was modeled for ground water and surface water (rivers). Ground-water flow and mass transport were modeled using EPA's Liner Location Risk and Cost Analysis Model (LLM) (USEPA 1986). The LLM

uses a series of predetermined flow field types to define ground-water conditions (see Table V-7); a transient-source, one-dimensional, wetting-front model to assess unsaturated zone transport; and a modified version of the Random Walk Solute Transport Model (Prickett et al. 1981) to predict ground-water flow and chemical transport in the saturated zone. All ground-water exposure and risk estimates presented in this report are for the downgradient center line plume concentration. Chemical transport in rivers was modeled using equations adapted from EPA (USEPA 1984a); these equations can account for dilution, dispersion, particulate adsorption, sedimentation, degradation (photolysis, hydrolysis, and biodegradation), and volatilization.

EPA used the LLM risk submodel to estimate cancer and chronic noncancer risks from the ingestion of contaminated ground and surface water. The measure used for cancer risk was the maximum (over the 200-year modeling period) lifetime excess[7] individual risk, assuming an individual ingested contaminated ground or surface water over an entire lifetime (assumed to be 70 years). These risk numbers represent the estimated probability of occurrence of cancer in an exposed individual. For example, a cancer risk estimate of 1×10^{-6} indicates that the chance of an individual getting cancer is approximately one in a million over a 70-year lifetime. The measure used for noncancer risk was the maximum (over the 200-year modeling period) ratio of the estimated chemical dose to the dose of the chemical at which health effects begin to occur (i.e., the threshold dose). Ratios exceeding 1.0 indicate the potential for adverse effects in some exposed individuals; ratios less than 1.0 indicate a very low likelihood of effect (assuming that background exposure is zero, as is done in this study). Although these ratios are <u>not</u> probabilities, higher ratios in general are cause for greater concern.

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7 Excess refers to the risk increment attributable only to exposure resulting from the releases considered in this analysis. Background exposures were assumed to be zero.

Table V-7 Definition of Flow Fields Used in Ground-Water Transport Modeling

	Key variables defining flow field[a]	
Flow field	Aquifer configuration[b]	Horizontal ground-water velocity
A	Unconfined aquifer	1 m/yr
B	Unconfined aquifer	10 m/yr
C	Unconfined aquifer	100 m/yr
D	Unconfined aquifer	1,000 m/yr
E	Unconfined aquifer	10,000 m/yr
F	Confined aquifer	0.05 m/yr in the confining layer and 100 m/yr within the aquifer
K	Confined aquifer	0.05 m/yr in the confining layer and 10 m/yr within the aquifer

[a]Several other variables, such as porosity, distinguish the flow fields, but the variables listed here are the most important for the purpose of this presentation.

[b]In general, an aquifer is defined as a geological unit that can transmit significant quantities of water. An unconfined aquifer is one that is only partly filled with water, such that the upper surface of the saturated zone is free to rise and decline. A confined aquifer is one that is completely filled with water and that is overlain by a confining layer (a rock unit that restricts the movement of ground water).

As a means of assessing potential effects on aquatic organisms, EPA estimated, for each model scenario involving surface water, the volume contaminated above an aquatic effects threshold. EPA also estimated the volumes of ground and surface water contaminated above various resource damage thresholds (e.g., the secondary drinking water standard for chloride).

QUANTITATIVE RISK MODELING RESULTS: HUMAN HEALTH

This section summarizes the health risk modeling results for onsite reserve pits (drilling wastes), underground injection wells (produced water), and direct discharges to surface water (produced water, stripper well scenarios only). Cancer risk estimates are presented separately from noncancer risk estimates throughout. This section also summarizes EPA's preliminary estimates of the size of populations that could possibly be exposed through drinking water.

Onsite Reserve Pits--Drilling Wastes

Cancer and noncancer health risks were analyzed under both best-estimate and conservative modeling assumptions for 1,134 model scenarios[8] of onsite reserve pits. Arsenic was the only potential carcinogen among the constituents modeled for onsite reserve pits. Of the noncarcinogens, only sodium exceeded its effect threshold; neither cadmium nor chromium VI exceeded their thresholds in any model scenarios (in its highest risk scenario, cadmium was at 15 percent of threshold; chromium VI, less than 1 percent).

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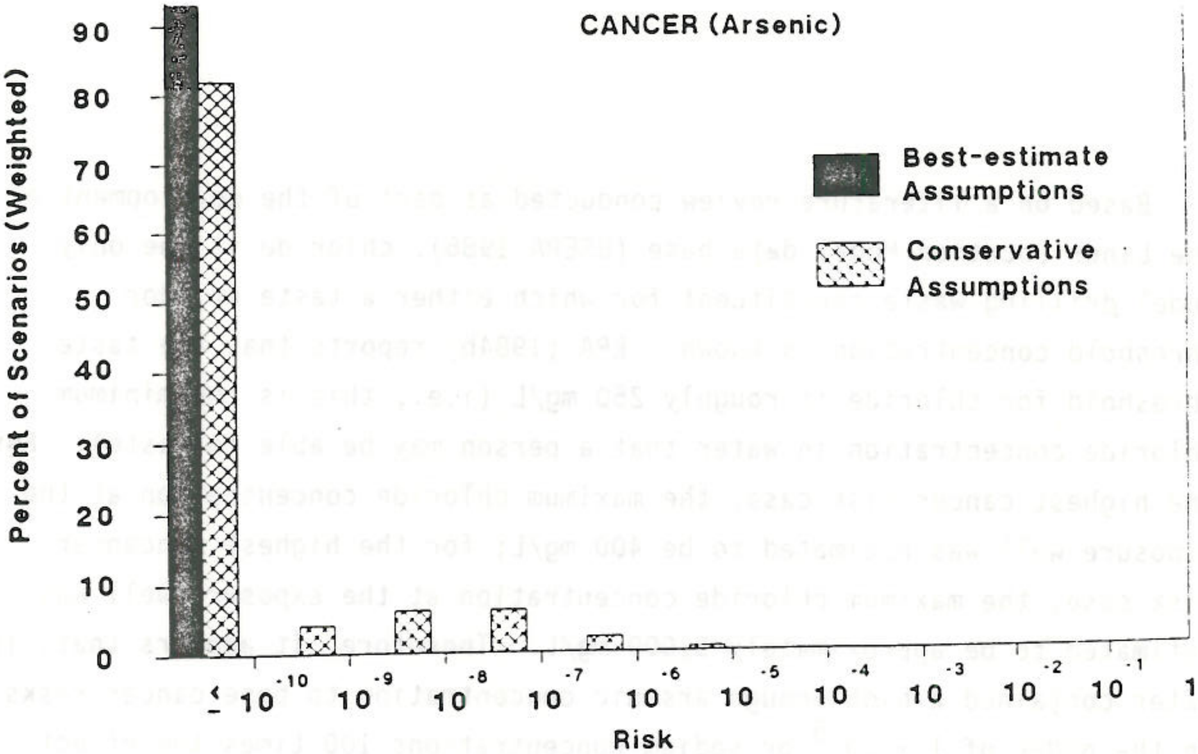
8 1,134 = 9 infiltration/unsaturated zone types x 7 ground-water flow field types x 3 exposure distances x 3 size categories x 2 liner types.

Nationally Weighted Risk Distributions

Figure V-3 presents the nationally weighted frequency distributions of human health risk estimates associated with unlined onsite reserve pits. The figure includes best-estimate and conservative modeling results for both cancer (top) and noncancer (bottom) risks. Only the results for unlined reserve pits are given because the presence or absence of a liner had little influence on risk levels (see section on major factors affecting health risk). Many of the scenarios in the figure show zero risk because the nearest potential exposure well was estimated to be more than 2 kilometers away (roughly 61 percent of all scenarios).

Under best-estimate assumptions, there were no cancer risks from arsenic because arsenic was not included as a constituent of the modeled waste (i.e., the median arsenic concentration in the field sampling data was below detection limits; see Table V-1). Under conservative assumptions, nonzero cancer risks resulting from arsenic were estimated for 18 percent of the nationally weighted reserve pit scenarios, with roughly 2 percent of the scenarios having cancer risks greater than 1×10^{-7}. Even under conservative modeling assumptions, drilling waste pit scenarios produced maximum lifetime cancer risks of less than 1 in 100,000 for individuals drinking affected water.

A few threshold exceedances for sodium were estimated under both best-estimate and conservative assumptions. Under best-estimate assumptions, more than 99 percent of nationally weighted reserve pit scenarios posed no noncancer risk (i.e., they were below threshold). A few model scenarios had noncancer risks, but none exceeded 10 times the sodium threshold. Under conservative assumptions, 98 percent of nationally weighted reserve pit scenarios did not pose a noncancer risk. The remaining 2 percent of reserve pit scenarios had estimated exposure point sodium concentrations between up to 32 times the threshold.



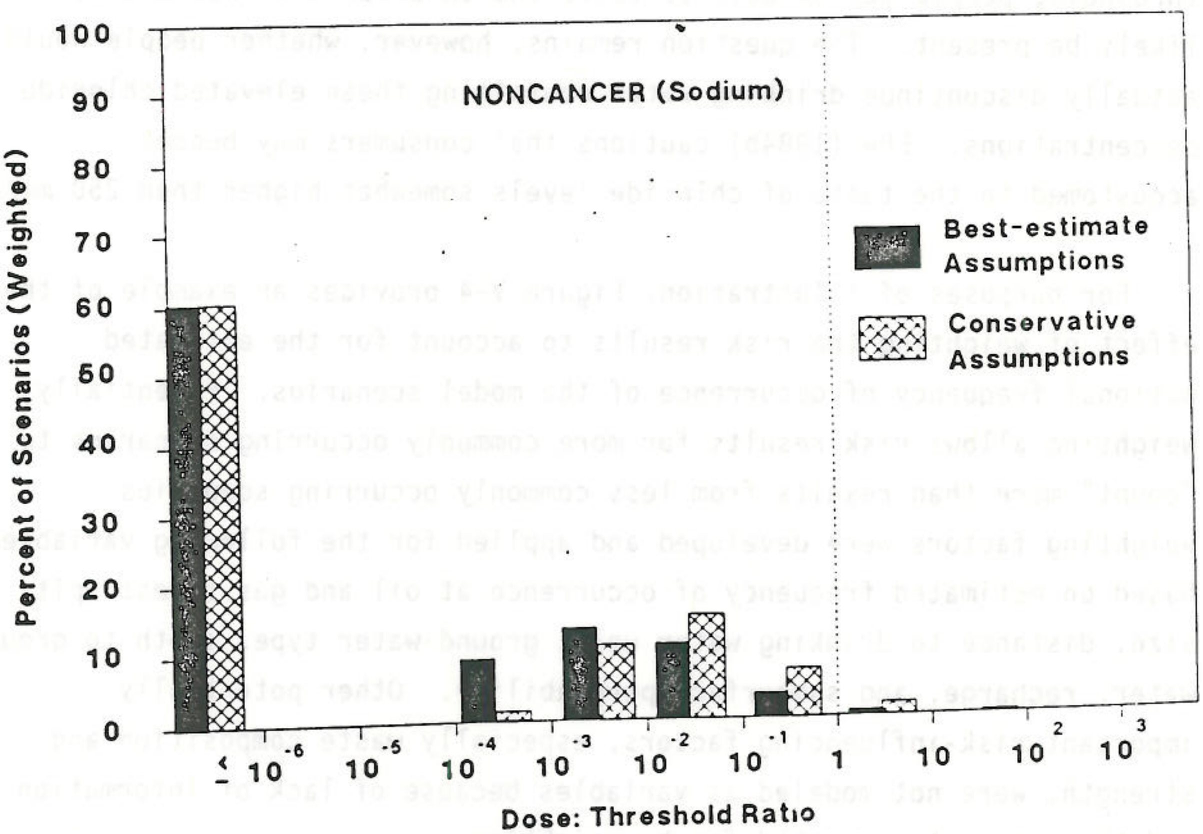


Figure V-3 Nationally Weighted Distribution of Health Risk Estimates. Unlined Reserve Pits

Based on a literature review conducted as part of the development of the Liner Location Model data base (USEPA 1986), chloride is the only model drilling waste constituent for which either a taste or odor threshold concentration is known. EPA (1984b) reports that the taste threshold for chloride is roughly 250 mg/L (i.e., this is the minimum chloride concentration in water that a person may be able to taste). For the highest cancer risk case, the maximum chloride concentration at the exposure well was estimated to be 400 mg/L; for the highest noncancer risk case, the maximum chloride concentration at the exposure well was estimated to be approximately 5,000 mg/L. Therefore, it appears that, if water contained a high enough arsenic concentration to pose cancer risks on the order of 1×10^{-5} or sodium concentrations 100 times the effect threshold, people may be able to taste the chloride that would also likely be present. The question remains, however, whether people would actually discontinue drinking water containing these elevated chloride concentrations. EPA (1984b) cautions that consumers may become accustomed to the taste of chloride levels somewhat higher than 250 mg/L.

For purposes of illustration, Figure V-4 provides an example of the effect of weighting the risk results to account for the estimated national frequency of occurrence of the model scenarios. Essentially, weighting allows risk results for more commonly occurring scenarios to "count" more than results from less commonly occurring scenarios. Weighting factors were developed and applied for the following variables, based on estimated frequency of occurrence at oil and gas sites: pit size, distance to drinking water well, ground-water type, depth to ground water, recharge, and subsurface permeability. Other potentially important risk-influencing factors, especially waste composition and strength, were not modeled as variables because of lack of information and thus are not accounted for by weighting.

In the example shown in Figure V-4 (conservative-estimate cancer risks for unlined onsite pits), weighting the risk results decreases the

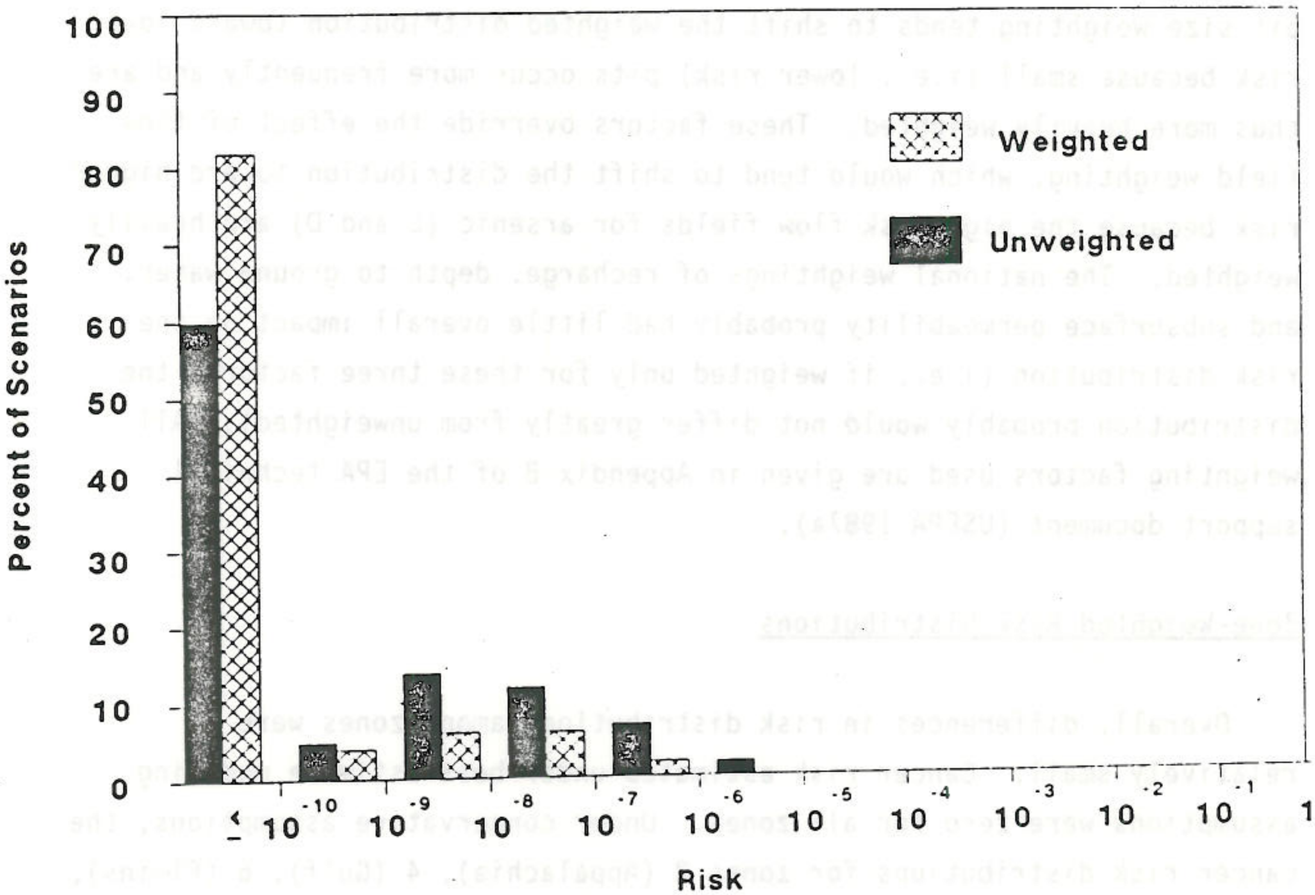


Figure V-4 Weighted vs. Unweighted Distribution of Cancer Risk Estimates. Unlined Reserve Pits. Conservative Modeling Assumptions

risk (i.e., shifts the distribution toward lower risk). This happens primarily because close exposure distances (60 and 200 meters), which correspond to relatively high risks, occur less frequently and thus are less heavily weighted than greater distances. In addition, the effect of pit size weighting tends to shift the weighted distribution toward lower risk because small (i.e., lower risk) pits occur more frequently and are thus more heavily weighted. These factors override the effect of flow field weighting, which would tend to shift the distribution toward higher risk because the high-risk flow fields for arsenic (C and D) are heavily weighted. The national weightings of recharge, depth to ground water, and subsurface permeability probably had little overall impact on the risk distribution (i.e., if weighted only for these three factors, the distribution probably would not differ greatly from unweighted). All weighting factors used are given in Appendix B of the EPA technical support document (USEPA 1987a).

Zone-Weighted Risk Distributions

Overall, differences in risk distributions among zones were relatively small. Cancer risk estimates under best-estimate modeling assumptions were zero for all zones. Under conservative assumptions, the cancer risk distributions for zones 2 (Appalachia), 4 (Gulf), 6 (Plains), and 7 (Texas/Oklahoma) were slightly higher than the distribution for the nation as a whole. The cancer risk distributions for zones 5 (Midwest), 8 (Northern Mountain), 9 (Southern Mountain), 10 (West Coast), and 11B (Alaska, non-North Slope) were lower than the nationally weighted distribution; zones 10 and 11B were much lower. The risk distributions for individual zones generally varied from the national distribution by less than one order of magnitude.

Noncancer risk estimates under best-estimate modeling assumptions were extremely low for all zones. Under conservative assumptions, zones 2, 4, 5, 7, and 8 had a small percentage (1 to 10 percent) of weighted

scenarios with threshold exceedances for sodium; other zones had less than 1 percent. There was little variability in the noncancer risk distributions across zones.

The reasons behind the differences in risks across zones are related to the zone-specific relative weightings of reserve pit size, distance to receptor populations, and/or environmental variables. For example, the main reason zone 10 has low risks relative to other zones is that 92 percent of drilling sites were estimated to be in an arid setting above a relatively low-risk ground-water flow field having an aquitard (flow field F). Zone 11B has zero risks because all potential exposure wells were estimated to be more than 2 kilometers away.

In summary, differences in cancer risks among the geographic zones were not great. Cancer risks were only prevalent in the faster aquifers (i.e., flow fields C, D, and E, with C having the highest cancer risks). Zone 4, with the highest cancer risks overall, also was assigned the highest weighting among the zones for flow field C. Noncancer risks caused by sodium were highest in zone 5. Noncancer risks occurred only in the more slow-moving flow fields (i.e., flow fields A, B, and K, with A having the highest noncancer risks); among the zones, zone 5 was assigned the highest weighting for flow field A. EPA considered the possible role of distributions of size and distance to exposure points, but determined that aquifer configuration and velocity probably contributed most strongly to observed zone differences in estimates of human health risks. The consistent lack of risk for zone 11B, however, is entirely because of the large distance to an exposure point. (See the section that follows on estimated population distributions.)

Evaluation of Major Factors Affecting Health Risk

EPA examined the effect of several parameters related to pit design and environmental setting that were expected to influence the release and

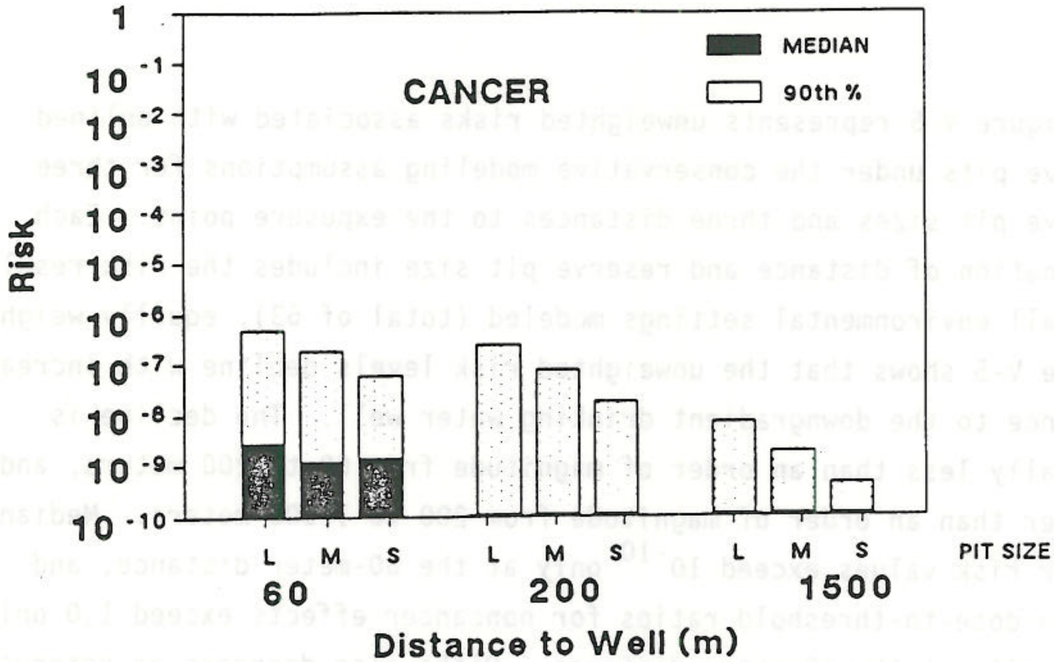
transport of contaminants leaking from onsite reserve pits. To assess the effect of each of these parameters in isolation, all other parameters were held constant for the comparisons. The results presented in this section are not weighted according to either national or zone-specific frequencies of occurrence. Instead, each model scenario is given equal weight. Thus, the following comparisons are not appropriate for drawing conclusions concerning levels of risk for the national population of onsite reserve pits. They are appropriate for examining the effect of selected parameters on estimates of human health risk.

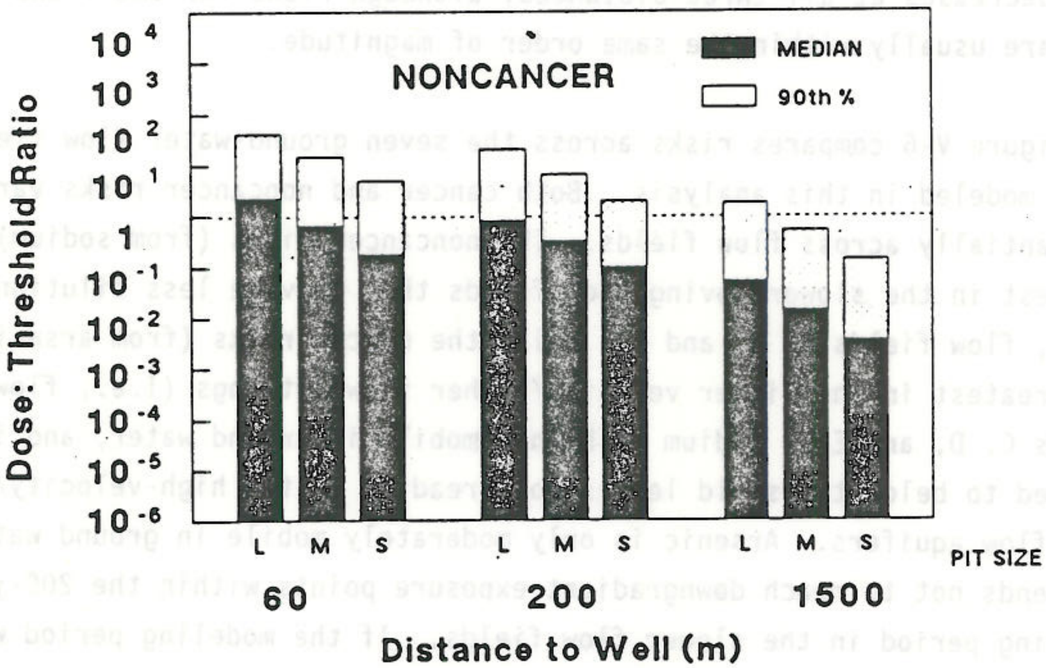
The presence or absence of a conventional, single synthetic liner underneath an onsite reserve pit had virtually no effect on the 200-year maximum health risk estimates. A liner does affect timing of exposures and risks, however, by reducing the amounts of leachate (and chemicals) released early in the modeling period. EPA's modeling assumed a single synthetic liner with no leak detection or leachate collection. (Note that this is significantly different from the required Subtitle C liner system design for hazardous waste land disposal units.) Furthermore, EPA assumed that such a liner would eventually degrade and fail, resulting in release of the contaminants that had been contained. Thus, over a long modeling period, mobile contaminants that do not degrade or degrade very slowly (such as the ones modeled here) will produce similar maximum risks whether they are disposed of in single-synthetic-lined or unlined pits (unless a significant amount of the contained chemical is removed, such as by dredging). This finding should not be interpreted to discount the benefit of liners in general. Measures of risk over time periods shorter than 200 years would likely be lower for lined pits than for unlined ones. Moreover, by delaying any release of contaminants, liners provide the opportunity for management actions (e.g., removal) to help prevent contaminant seepage and to mitigate seepage should it occur.

Figure V-5 represents unweighted risks associated with unlined reserve pits under the conservative modeling assumptions for three reserve pit sizes and three distances to the exposure point. Each combination of distance and reserve pit size includes the risk results from all environmental settings modeled (total of 63), equally weighted. Figure V-5 shows that the unweighted risk levels decline with increasing distance to the downgradient drinking water well. The decline is generally less than an order of magnitude from 60 to 200 meters, and greater than an order of magnitude from 200 to 1,500 meters. Median cancer risk values exceed 10^{-10} only at the 60-meter distance, and median dose-to-threshold ratios for noncancer effects exceed 1.0 only for large pits at the 60-meter distance. Risks also decrease as reserve pit size decreases at all three distances, although risks for small and large pits are usually within the same order of magnitude.

Figure V-6 compares risks across the seven ground-water flow field types modeled in this analysis. Both cancer and noncancer risks vary substantially across flow fields. The noncancer risks (from sodium) are greatest in the slower moving flow fields that provide less dilution (i.e., flow fields A, B, and K), while the cancer risks (from arsenic) are greatest in the higher velocity/higher flow settings (i.e., flow fields C, D, and E). Sodium is highly mobile in ground water, and it is diluted to below threshold levels more readily in the high-velocity/high-flow aquifers. Arsenic is only moderately mobile in ground water and tends not to reach downgradient exposure points within the 200-year modeling period in the slower flow fields. If the modeling period were extended, cancer risks resulting from arsenic would appear in the more slowly moving flow field scenarios.

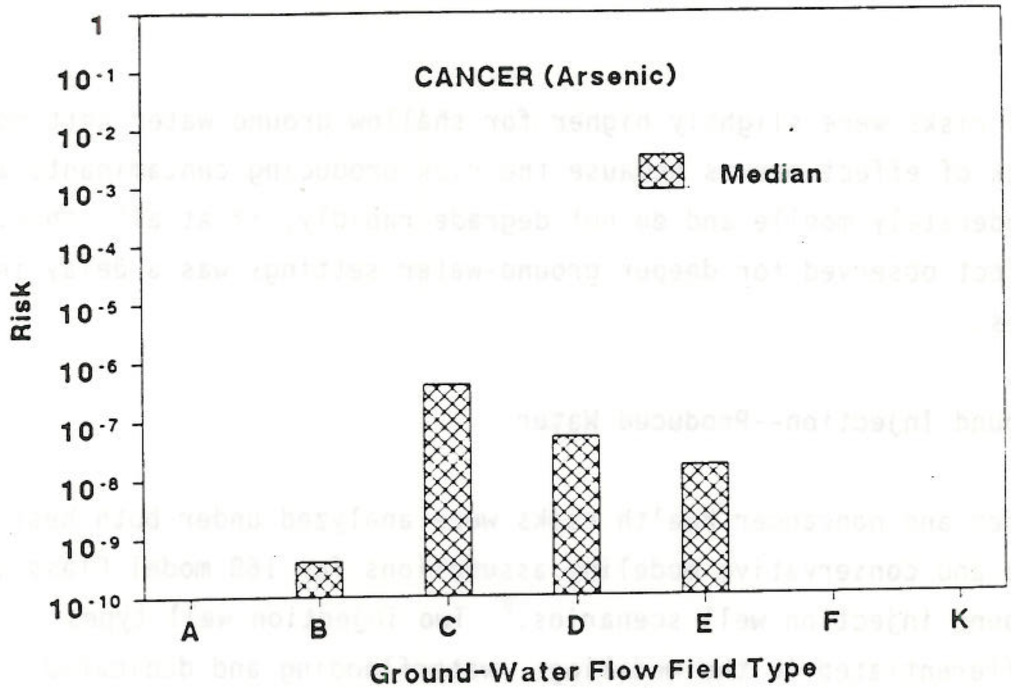
As would be expected, both cancer and noncancer risks increased with increasing recharge rate and with increasing subsurface permeability. Risk differences were generally less than an order of magnitude. Depth to ground water had very little effect on the 200-year maximum risk,





L = Large, M = Medium, S = Small Reserve Pits

Figure V-5 Health Risk Estimates (Unweighted) as a Function of Size and Distance. Unlined Reserve Pits. Conservative Modeling Assumptions



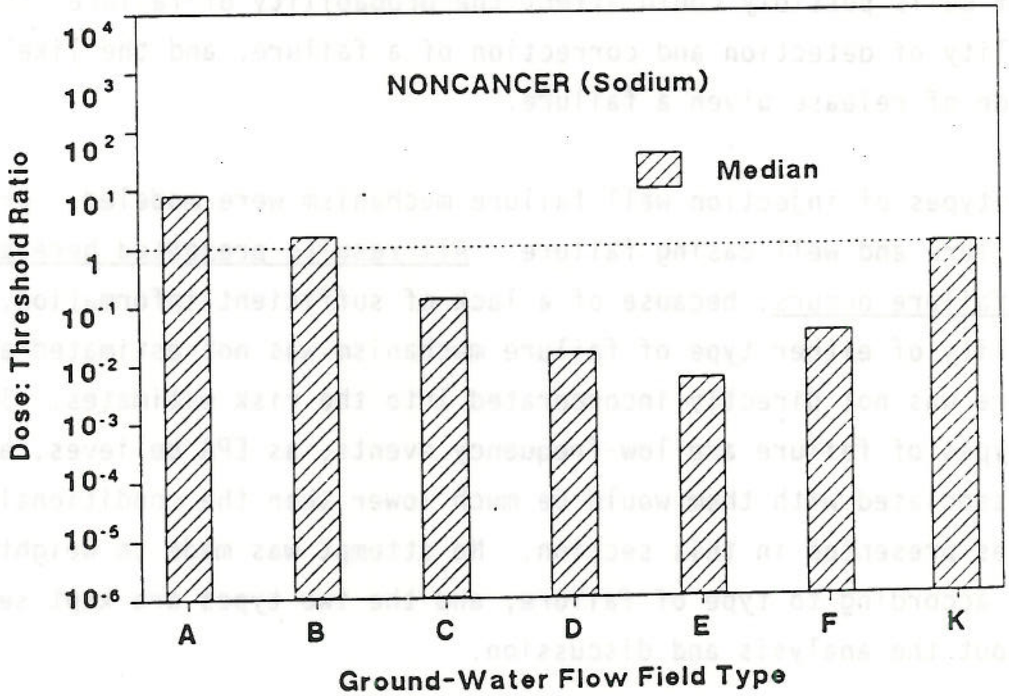


Figure V-6 Health Risk Estimates (Unweighted) as a Function of Ground-Water Type. Unlined Reserve Pits (Large). 60-Meter Exposure Distance. Conservative Modeling Assumptions

although risks were slightly higher for shallow ground-water settings. This lack of effect occurs because the risk-producing contaminants are at least moderately mobile and do not degrade rapidly, if at all; thus, the main effect observed for deeper ground-water settings was a delay in exposures.

Underground Injection--Produced Water

Cancer and noncancer health risks were analyzed under both best-estimate and conservative modeling assumptions for 168 model Class II underground injection well scenarios.[9] Two injection well types were differentiated in the modeling: waterflooding and dedicated disposal. Design, operating, and regulatory differences between the two types of wells possibly could affect the probability of failure, the probability of detection and correction of a failure, and the likely magnitude of release given a failure.

Two types of injection well failure mechanism were modeled: grout seal failure and well casing failure. <u>All results presented here assume that a failure occurs</u>; because of a lack of sufficient information, the probability of either type of failure mechanism was not estimated and therefore was not directly incorporated into the risk estimates. If these types of failure are low-frequency events, as EPA believes, actual risks associated with them would be much lower than the conditional risk estimates presented in this section. No attempt was made to weight risk results according to type of failure, and the two types are kept separate throughout the analysis and discussion.

Nationally Weighted Risk Distributions

The risk estimates associated with injection well failures were weighted based on the estimated frequency of occurrence of the following

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9 168 = 7 ground-water flow field types x 3 exposure distances x 2 size categories x 2 well types x 2 failure mechanisms.

variables: injection well type, distance to nearest drinking water well, and ground-water flow field type. In addition, all risk results for grout seal failure were weighted based on injection rate. As for reserve pits, insufficient information was available to account for waste characteristics and other possibly important variables by weighting.

Grout seal failure: Best-estimate cancer risks, given a grout seal failure, were estimated to be zero for more than 85 percent of the model scenarios. The remaining scenarios had slightly higher risks but never did the best-estimate cancer risk exceed 1×10^{-7}. Under conservative assumptions, roughly 65 percent of the scenarios were estimated to have zero cancer risk, while the remaining 35 percent were estimated to have cancer risks ranging up to 4×10^{-4} (less than 1 percent of the scenarios had greater than 1×10^{4} risk). These modeled cancer risks were attributable to exposure to two produced water constituents, benzene and arsenic. Figure V-7 (top portion) provides a nationally weighted frequency distribution of the best-estimate and conservative-estimate cancer risks, given a grout seal failure. Figure V-7 shows the combined distribution for the two well types and two injection rates considered in the analysis, the three exposure distances, and the seven ground-water settings. As with drilling pits, many of the zero risk cases were because the nearest potential exposure well was estimated to be more than 2 kilometers away (roughly 64 percent of all scenarios).

Modeled noncancer risks, given a grout seal failure, are entirely attributable to exposures to sodium. There were no sodium threshold exceedances associated with grout seal failures under best-estimate conditions. Under conservative conditions, roughly 95 percent of the nationally weighted model scenarios also had no noncancer risk. The remaining 5 percent had estimated sodium concentrations at the exposure point that exceeded the effect threshold, with the maximum concentration exceeding the effect threshold by a factor of 70. The nationally

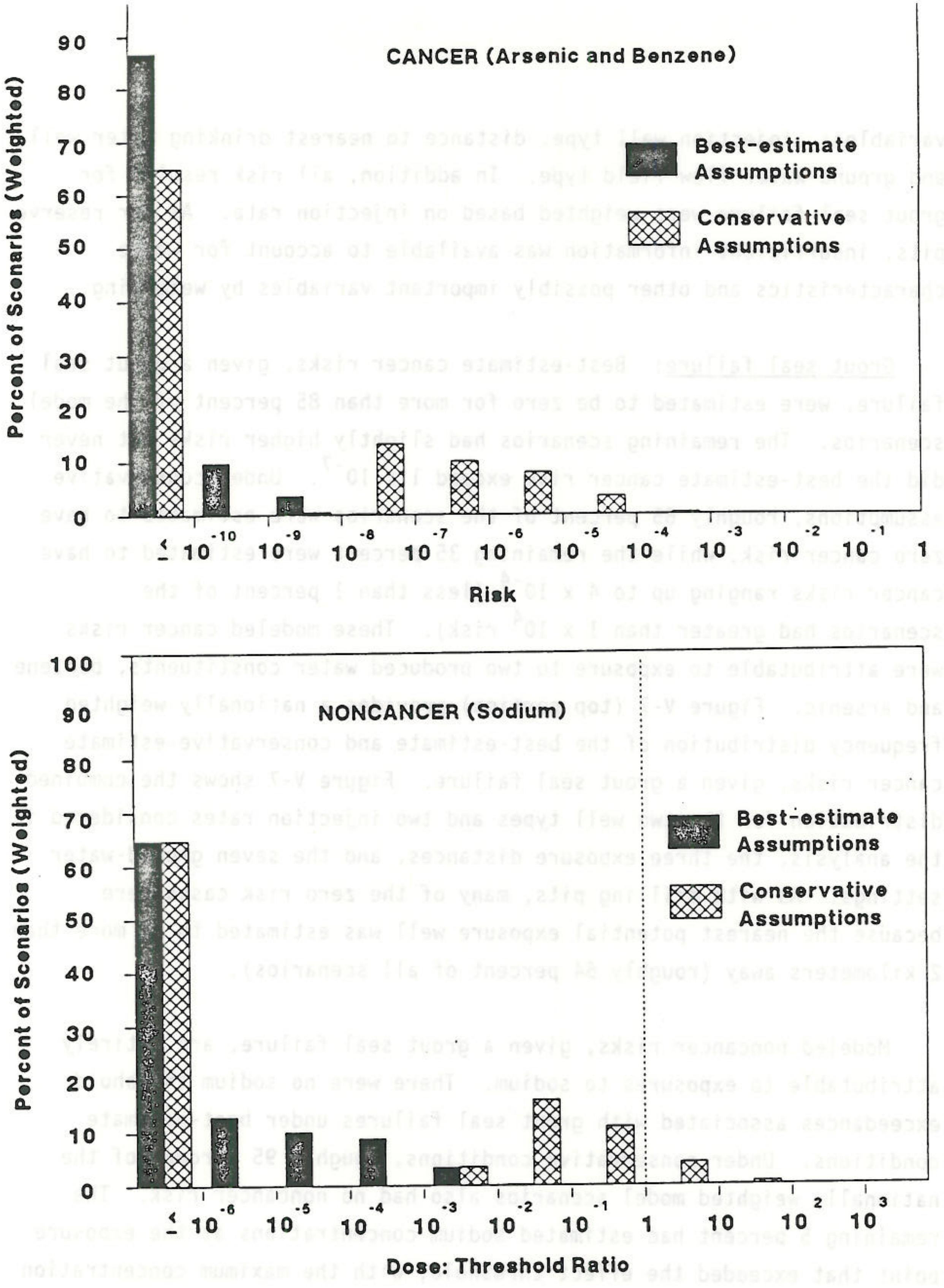


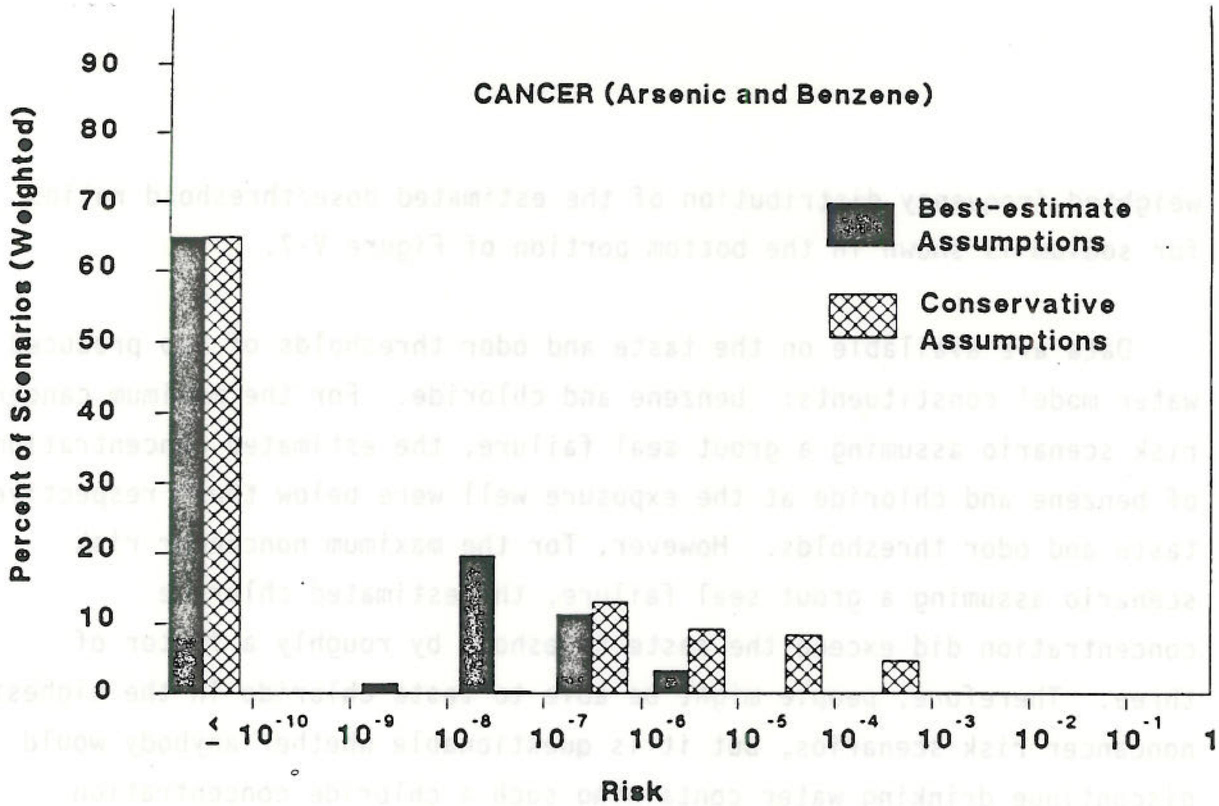
Figure V-7 Nationally Weighted Distribution of Health Risk Estimates. Underground Injection Wells: Grout Seal Failure Assumed

weighted frequency distribution of the estimated dose/threshold ratios for sodium is shown in the bottom portion of Figure V-7.

Data are available on the taste and odor thresholds of two produced water model constituents: benzene and chloride. For the maximum cancer risk scenario assuming a grout seal failure, the estimated concentrations of benzene and chloride at the exposure well were below their respective taste and odor thresholds. However, for the maximum noncancer risk scenario assuming a grout seal failure, the estimated chloride concentration did exceed the taste threshold by roughly a factor of three. Therefore, people might be able to taste chloride in the highest noncancer risk scenarios, but it is questionable whether anybody would discontinue drinking water containing such a chloride concentration.

Well casing failure: The nationally weighted distributions of estimated cancer and noncancer risks, given an injection well casing failure, are presented in Figures V-8 and V-9. Figure V-8 gives the risk distributions for scenarios with high injection pressure, and Figure V-9 gives the risk distributions for scenarios with low injection pressure. (Because of a lack of adequate data to estimate the distribution of injection pressures, results for the high and low pressure categories were not weighted and therefore had to be kept separate.)

Best-estimate cancer risks, given a casing failure, were zero for approximately 65 percent of both the high and low pressure scenarios; the remaining scenarios had cancer risk estimates ranging up to 5×10^{-6} for high pressure and 1×10^{-6} for low pressure. The majority (65 percent) of both high and low pressure scenarios also had no cancer risks under the conservative assumptions, although approximately 5 percent of the high pressure scenarios and 1 percent of the low pressure scenarios had conservative-estimate cancer risks greater than 1×10^{-4} (maximum of 9×10^{4}). The rest of the scenarios had conservative-estimate cancer risks greater than zero and less than 1×10^{-4}.



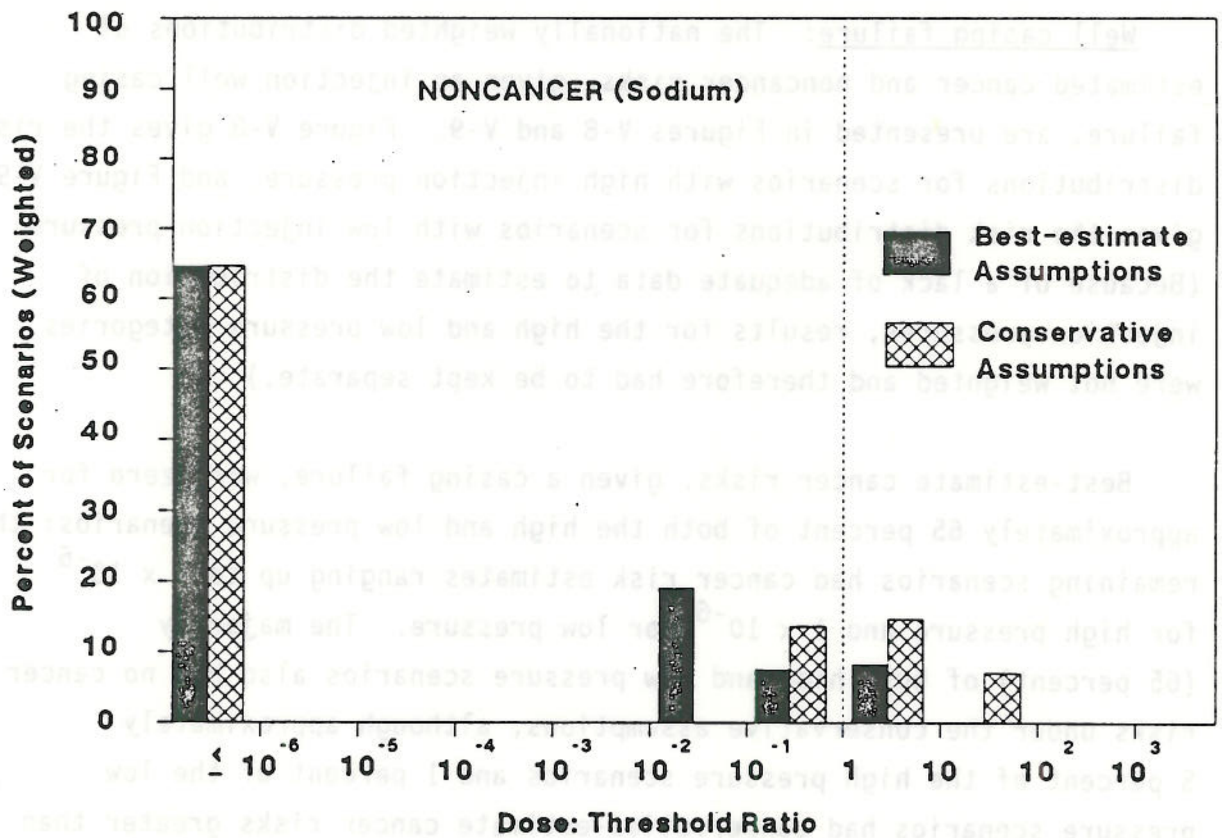


Figure V-8 Nationally Weighted Distribution of Health Risk Estimates. High Pressure Underground Injection Wells: Casing Failure Assumed

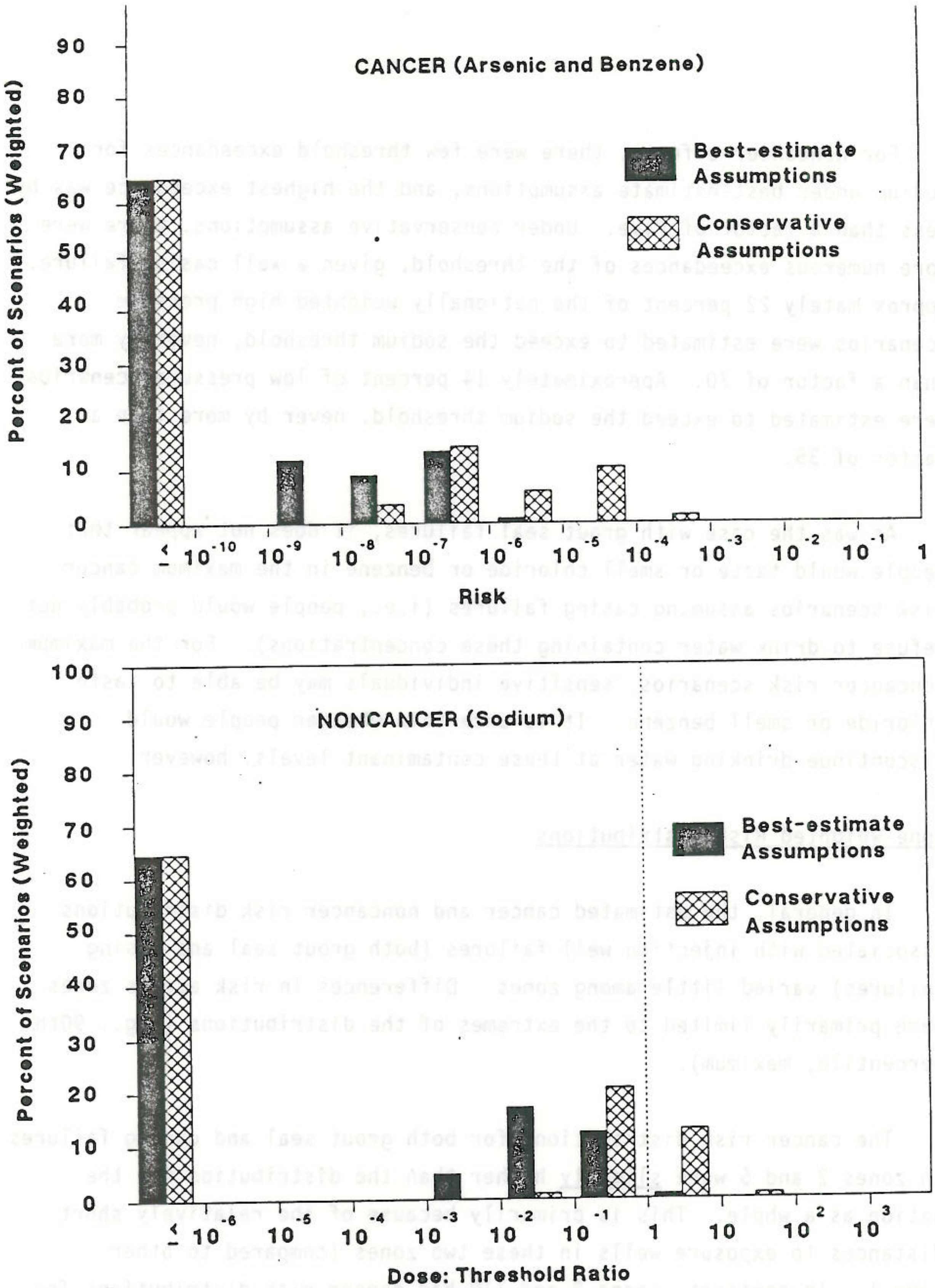


Figure V-9 Nationally Weighted Distribution of Health Risk Estimates. Low Pressure Underground Injection Wells: Casing Failure Assumed

For noncancer effects, there were few threshold exceedances for sodium under best-estimate assumptions, and the highest exceedance was by less than a factor of five. Under conservative assumptions, there were more numerous exceedances of the threshold, given a well casing failure. Approximately 22 percent of the nationally weighted high pressure scenarios were estimated to exceed the sodium threshold, never by more than a factor of 70. Approximately 14 percent of low pressure scenarios were estimated to exceed the sodium threshold, never by more than a factor of 35.

As was the case with grout seal failures, it does not appear that people would taste or smell chloride or benzene in the maximum cancer risk scenarios assuming casing failures (i.e., people would probably not refuse to drink water containing these concentrations). For the maximum noncancer risk scenarios, sensitive individuals may be able to taste chloride or smell benzene. It is uncertain whether people would discontinue drinking water at these contaminant levels, however.

Zone-Weighted Risk Distributions

In general, the estimated cancer and noncancer risk distributions associated with injection well failures (both grout seal and casing failures) varied little among zones. Differences in risk across zones were primarily limited to the extremes of the distributions (e.g., 90th percentile, maximum).

The cancer risk distributions for both grout seal and casing failures in zones 2 and 5 were slightly higher than the distribution for the nation as a whole. This is primarily because of the relatively short distances to exposure wells in these two zones (compared to other zones). In contrast, zones 8 and 11B had cancer risk distributions for injection well failures that were slightly lower than the national

distribution. This difference is primarily because of the relatively long distance to exposure wells in these zones. (For almost 80 percent of production sites in both zones, it was estimated that the closest exposure well was more than 2 kilometers away.) A similar pattern of zone differences was observed for the noncancer risk results.

Evaluation of Major Factors Affecting Health Risk

In general, estimated risks associated with well casing failure are from one to two orders of magnitude higher than risks associated with grout seal failure. This is because under most conditions modeled, well casing failures are estimated to release a greater waste volume, and thus a larger mass of contaminants, than grout seal failures.

The risks estimated for disposal and waterflood wells are generally similar in magnitude. For assumed casing failures, waterflood wells are estimated to cause slightly (no more than a factor of 2.5 times) higher risks than disposal wells. This pattern is the net result of two differences in the way waterflood and disposal wells were modeled. The release durations modeled for disposal wells are longer than those for waterflood wells, but the injection pressures modeled for waterflood wells are greater than those modeled for disposal wells. For assumed grout seal failures, disposal wells are estimated to cause slightly (no more than a factor of 3 times) higher risks than waterflood wells. This pattern results because the injection rates modeled for disposal wells are up to 3 times greater than those modeled for waterflood wells.

The distance to a potentially affected exposure well at an injection site is one of the most important indicators of risk potential. If all other parameters remain constant, carcinogenic risks decline slightly less than one order of magnitude between the 60-meter and 200-meter well distances; carcinogenic risks decline between one and two orders of

magnitude from the 200-meter to the 1,500-meter well distances. The effect of well distance is a little less pronounced for noncarcinogenic risks. Sodium threshold exceedances drop by less than an order of magnitude between the 60-meter and 200-meter well distances and by approximately one order of magnitude between the 200-meter and 1,500-meter well distances. The reduction in exposure with increased distance from the well is attributable to three-dimensional dispersion of contaminants within the saturated zone. In addition, the 200-year modeling period limits risks resulting from less mobile constituents at greater distances (especially 1,500 meters). Degradation is not a factor because the constituents producing risk degrade very slowly (if at all) in the saturated zone.

Cancer and noncancer risk estimates decrease with decreasing injection rate/pressure. This relationship reflects the dependence of risk upon the total chemical mass released into the aquifer each year, which is proportional to either the assumed injection flow rate (grout seal failure) or pressure (casing failure).

Figure V-10 shows how the unweighted health risk estimates associated with injection well casing failures varied for the different ground-water flow fields. The figure includes only results for the conservative modeling assumptions, the high injection pressure, and the 60-meter modeling distance, because risk estimates under best-estimate assumptions and for other modeling conditions were substantially reduced and less varied. As shown, conservative-estimate carcinogenic risks ranged from roughly 2×10^{-6} (for flow field F) to approximately 6×10^{-4} (for flow field D). The difference in the risk estimates for these two flow fields is due primarily to their different aquifer configurations. Flow field D represents an unconfined aquifer, which is more susceptible to contamination than a confined aquifer setting represented by flow field F.

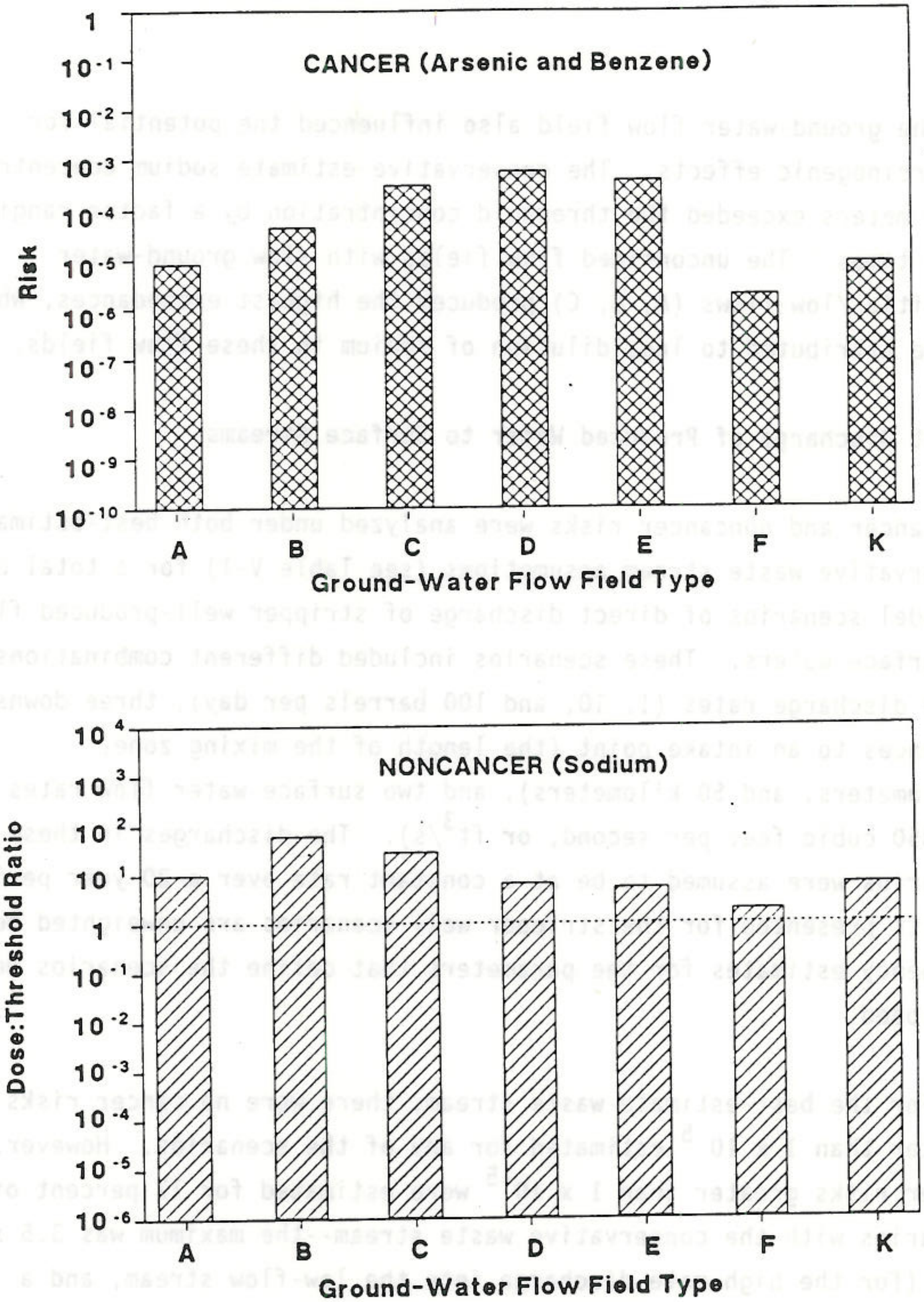


Figure V-10 Health Risk Estimates (Unweighted) as a Function of Ground-Water Type. High Pressure Underground Injection Wells: Casing Failure Assumed. 60-Meter Exposure Distance. Conservative Modeling Assumptions

The ground-water flow field also influenced the potential for noncarcinogenic effects. The conservative-estimate sodium concentrations at 60 meters exceeded the threshold concentration by a factor ranging up to 70 times. The unconfined flow fields with slow ground-water velocities/low flows (A, B, C) produced the highest exceedances, which can be attributed to less dilution of sodium in these flow fields.

Direct Discharge of Produced Water to Surface Streams

Cancer and noncancer risks were analyzed under both best-estimate and conservative waste stream assumptions (see Table V-1) for a total of 18 model scenarios of direct discharge of stripper well-produced fluids to surface waters. These scenarios included different combinations of three discharge rates (1, 10, and 100 barrels per day), three downstream distances to an intake point (the length of the mixing zone, 5 kilometers, and 50 kilometers), and two surface water flow rates (40 and 850 cubic feet per second, or ft^3/s). The discharges in these scenarios were assumed to be at a constant rate over a 20-year period. Results presented for the stripper well scenarios are unweighted because frequency estimates for the parameters that define the scenarios were not developed.

For the best-estimate waste stream, there were no cancer risks greater than 1×10^{-5} estimated for any of the scenarios. However, cancer risks greater than 1×10^{-5} were estimated for 17 percent of the scenarios with the conservative waste stream--the maximum was 3.5×10^{-5} (for the high-rate discharge into the low-flow stream, and a drinking water intake immediately downstream of the discharge point). These cancer risks were due primarily to exposure to arsenic, although benzene also contributed slightly. For noncancer risks, none of the scenarios had a threshold exceedance for sodium, regardless of whether the best-estimate or conservative waste stream was assumed.

EPA recognizes that the model surface water flow rates (40 and 850 ft^3/s) are relatively high and that discharges into streams or rivers with flow rates less than 40 ft^3/s could result in greater risks than are presented here. Therefore, to supplement the risk results for the model scenarios, EPA analyzed what a river or stream flow rate would have to be (given the model waste stream concentrations and discharges rates) in order for the contaminant concentration in the mixing zone (assuming instantaneous and complete mixing but no other removal processes) to be at certain levels.

The results of this analysis, presented in Table V-8, demonstrate that reference concentrations of benzene would be exceeded only in very low-flow streams (i.e., less than 5 ft^3/s) under all of the model conditions analyzed. It is unlikely that streams of this size would be used as drinking water sources for long periods of time. However, concentrations of arsenic and sodium under conservative modeling conditions could exceed reference levels in the mixing zone in relatively large streams, which might be used as drinking water sources. The concentrations would be reduced at downstream distances, although estimates of the surface water flow rates corresponding to reference concentrations at different distances have not been made.

Potentially Exposed Population

Preliminary estimates of the potentially exposed population were developed by estimating the number of individuals using private drinking water wells and public water supplies located downgradient from a sample of oil and gas wells. These estimates were based on data obtained from local water suppliers and 300 USGS topographic maps. One hundred of the maps were selected from areas containing high levels of drilling activity, and 200 were selected from areas containing high levels of production.

Table V-8 Surface Water Flow Rates At Which Concentrations of Waste Stream Constituents in the Mixing Zone Will Exceed Reference Levels[a]

Constituent	Concentration in waste	Waste stream discharge rate: High (100 BPD)	Medium (10 BPD)	Low (1 BPD)
Arsenic	Median	$\leq$ 5 ft^3/s[b]	$\leq$0.5 ft^3/s	$\leq$ .05 ft^3/s
	90th %	$\leq$ 470 ft^3/s	$\leq$50 ft^3/s	$\leq$5 ft^3/s
Benzene	Median	$\leq$ 1 ft^3/s	$\leq$ 0.1 ft^3/s	$\leq$ 0.01 ft^3/s
	90th %	$\leq$ 3 ft^3/s	$\leq$ 0.3 ft^3/s	$\leq$ 0.03 ft^3/s
Sodium	Median	$\leq$ 3 ft^3/s	$\leq$ 0.3 ft^3/s	$\leq$ 0.03 ft^3/s
	90th %	$\leq$ 20 ft^3/s	$\leq$ 2 ft^3/s	$\leq$ 0.2 ft^3/s

[a]The reference levels referred to are the arsenic and benzene concentrations that correspond to a 1×10^{-5} lifetime cancer risk level (assuming a 70-kg individual ingests 2 L/d) and EPA's suggested guidance level for sodium for the prevention of hypertension in high-risk individuals.

[b]Should be interpreted to mean that the concentration of arsenic in the mixing zone would exceed the 1×10^{-5} lifetime cancer risk level if the receiving stream or river was flowing at a rate of 5 ft^3/s or lower. If the stream or river was flowing at a higher rate, then the maximum concentration of arsenic would not exceed the 1×10^{-5} lifetime cancer risk level.

Table V-9 summarizes the sample results for the population potentially exposed through private drinking water wells. As shown in this table, over 60 percent of the oil and gas wells in both the drilling and production sample did not have private drinking water wells within 2,000 meters downgradient and only 2 percent of the oil and gas wells were estimated to have private drinking water wells within the 60-meter (i.e., higher-risk) distance category. Moreover, the numbers of potentially affected people per oil and gas well in the 60-meter distance category were relatively small. One other interesting finding demonstrated in Table V-9 is that fewer potentially affected individuals were estimated to be in the 1,500-meter distance category than in the 200-meter category. This situation is believed to occur because some residences located farther from oil and gas wells were on the other side of surface waters that appeared to be a point of ground-water discharge.

The sample results for the population potentially exposed through public water supplies are summarized in Table V-10. These results show a pattern similar to those for private drinking water wells; this is, most oil and gas wells do not have public water supply intakes within 2,000 meters and of those that do only a small fraction have public water supply intakes within the 60-meter distance category.

The results in Tables V-9 and V-10 are for the nation as a whole. Recognizing the limitations of the sample and of the analysis methods, EPA's data suggest that zone 2 (Appalachia) and zone 7 (Texas/Oklahoma) have the greatest relative number of potentially affected individuals per oil and gas well (i.e., potentially affected individuals are, on the average, closer to oil and gas wells in these zones relative to other zones). In addition, zone 4 (Gulf) has a relatively large number of individuals potentially affected through public water supplies. Zone 11 (Alaska) and zone 8 (Northern Mountain) appear to have relatively fewer potentially affected individuals per oil and gas well. Further

Table V-9 Population Potentially Exposed Through Private Drinking Water Wells at Sample Drilling and Production Areas

	Drilling sample results		Production sample results	
Distance category[a]	No. (%) of oil/gas wells with private drinking water wells within distance category	Maximum no. of potentially affected individuals per oil and gas well[b]	No. (%) of oil/gas wells with private drinking water wells within distance category	Maximum no. of potentially affected individuals per oil and gas well[b]
60 meters	561(2)	0.11	642(2)	0.17
200 meters	4,765(17)	0.44	5,139(16)	0.58
1,500 meters	5,606(20)	0.32	5,460(17)	0.36
>2,000 meters	17,096(61)	NA[c]	20,879(65)	NA

[a]Drinking water wells were counted as 60 meters downgradient if they were within 0 and 130 meters, were counted as 200 meters downgradient if they were within 130 and 800 meters, and were counted as 1,500 meters downgradient if they were within 800 and 2,000 meters.

[b]These ratios largely overestimate the number of people actually affected per oil and gas well (see text) and should be used to estimate the total number of people affected only with caution. The figures are intended simply to give a preliminary indication of the potentially exposed population and the distribution of that population in different distance categories.

[c]Not available; distances greater than 2,000 meters from oil and gas wells were not modeled.

Table V-10 Population Potentially Exposed Through Public Water Supplies at Sample Drilling and Production Areas

	Drilling sample results			Production sample results		
Distance category[a]	No. (%) of oil/gas wells with private drinking water wells within distance category		Maximum no. of potentially affected individuals per oil and gas well[b]	No. (%) of oil/gas wells with private drinking water wells within distance category		Maximum no. of potentially affected individuals per oil and gas well[b]
60 meters	87	(0.3)	3.6	54	(0.2)	96
200 meters	217	(0.8)	0.76	210	(0.7)	8.1
1,500 meters	232	(0.8)	0.55	617	(2)	3.9
>2,000 meters	27,492	(98)	NA[c]	31,239	(97)	NA[c]

[a]Public water supply intakes were counted as 60 meters downgradient if they were within 0 and 130 meters, were counted as 200 meters downgradient if they were within 130 and 800 meters, and were counted as 1,500 meters downgradient if they were within 800 and 2,000 meters.

[b]These ratios largely overestimate the number of people actually affected per oil and gas well (see text) and should be used to estimate the total number of people affected only with caution. The figures are intended simply to give a preliminary indication of the potentially exposed population and the distribution of that population in different distance categories.

[c]Not available; distances greater than 2,000 meters from oil and gas wells were not modeled.

discussion of the differences in population estimates across zones is provided in the supporting technical report (USEPA 1987a).

The number of potentially affected people per oil and gas well in Tables V-9 and V-10 represents the maximum number of people in the sample that could be affected if all the oil and gas wells in the sample resulted in ground-water contamination out to 2,000 meters. The number of persons actually affected is probably much smaller because ground water may not be contaminated at all (if any) of the sites, some of the individuals may rely on surface water or rainwater rather than on ground water, and some of the individuals and public water supplies may not have drinking water wells that are hydraulically connected to possible release sources. Also, the sample population potentially exposed through public water supplies is probably far less than estimated, because public water is frequently treated prior to consumption (possibly resulting in the removal of oil and gas waste contaminants) and because many supply systems utilize multiple sources of water, with water only at times being drawn from possibly contaminated sources. Therefore, these ratios largely overestimate the number of people actually exposed per oil and gas well and should be used to estimate the total number of people affected only with caution. The figures are intended simply to give a preliminary indication of the potentially exposed population and the distribution of that population in different distance categories.

QUANTITATIVE RISK MODELING RESULTS: RESOURCE DAMAGE

For the purposes of this study, resource damage is defined as the exceedance of pre-set threshold (i.e., "acceptable") concentrations for individual contaminants, based on levels associated with aquatic toxicity, taste and odor, or other adverse impacts. Potential ground-water and surface water damage was measured as the maximum (over the 200-year modeling time period) annual volume of contaminated water

flowing past various points downgradient or downstream of the source. Only the volume of water that exceeded a damage threshold concentration was considered to be contaminated. This measure of potential ground-water and surface water damage was computed for each of three distances downgradient or downstream from a source: 60, 200, and 1,500 meters.

These estimates of resource damage supplement, but should be considered separate from, the damage cases described in Chapter IV. The resource damage results summarized here are strictly for the model scenarios considered in this analysis, which represent: (1) seepage of reserve pit wastes; (2) releases of produced water from injection well failures; and (3) direct discharge of produced water from stripper wells to streams and rivers. While these releases may be similar to some of the damage cases described in Chapter IV, no attempt was made to correlate the scenarios to any given damage case(s). In addition, Chapter IV describes damage cases from several types of releases (e.g., land application) that were not modeled as part of this quantitative risk analysis.

Potential Ground-Water Damage--Drilling Wastes

Two contaminants were modeled for ground-water resource damage associated with onsite reserve pits. These contaminants were chloride ions in concentrations above EPA's secondary maximum contaminant level and total mobile ions (TMI) in concentrations exceeding the level of total dissolved salts predicted to be injurious to sensitive and moderately sensitive crops. Chloride is highly mobile in ground water and the other ions were assumed to be equally mobile.

On a national basis, the risks of significant ground-water damage were very low for the model scenarios included in the analysis. Under

the best-estimate modeling assumptions, only 2 percent of nationally weighted reserve pit scenarios were estimated to cause measurable ground-water damage at 60 meters resulting from TMI. Under the conservative modeling assumptions, less than 10 percent of reserve pits were associated with ground-water plumes contaminated by chloride and TMI at 60 meters and fewer than 2 percent at 200 meters. On a regional basis, the upper 90th percentile of the distributions for resource damage, under conservative modeling assumptions, were above zero for zones 2, 5, and 8. This zone pattern is similar to the zone pattern of noncancer human health risks from sodium. Flow field A was more heavily weighted for these three zones than for the remaining zones, and this flow field also was responsible for the highest downgradient concentrations of sodium of all the flow fields modeled.

The mobilities of chloride and total mobile salts in ground water were the same as the mobility of sodium, which was responsible for the noncancer human health risks. Thus, the effects of several pit design and environmental parameters on the volume of ground water contaminated above criteria concentrations followed trends very similar to those followed by the noncancer human health risks. These parameters included reserve pit size, net recharge, subsurface permeability, and depth to ground water. In contrast to the trend in noncancer human health risks, however, the magnitude of resource damage sometimes increased with increasing distance from the reserve pit. This is because contaminant concentrations (and thus health risks) decrease with distance traveled; however, the width of a contaminant plume (and thus the volume of contaminated water) increases up to a point with distance traveled. Eventually, however, the center line concentration of the plume falls below threshold, and the estimated volume of contaminated water at that distance falls to zero. Finally, as was the case with noncancer human health risks, only the slower aquifers were associated with significant estimates of resource damage.

Potential Ground-Water Damage--Produced Water

As they were for drilling wastes, chloride and total mobile ions were modeled to estimate ground-water resource damage associated with underground injection of produced water. Under best-estimate conditions, the risk of ground water becoming contaminated above the thresholds if injection well casing failures were to occur was negligible. Furthermore, in all but a few scenarios (approximately 1 percent of the nationally weighted scenarios), the resource damage estimates did not exceed zero under conservative assumptions. Estimated resource damage was almost entirely confined to the 60-meter modeling distance.

Grout seal failures were estimated to pose a slightly smaller risk of contaminating ground water above the chloride or TMI thresholds than injection well casing failures. In roughly 99 percent of the nationally weighted scenarios, grout seal failures never resulted in threshold exceedances, regardless of the set of conditions assumed (best-estimate vs. conservative) or the downgradient distance analyzed. Again, estimated resource damage was almost entirely confined to the 60-meter modeling distance.

In general, injection well failures were estimated to contaminate larger volumes of ground water above the damage criteria under conditions involving higher injection rates/pressures and lower ground-water velocities/flows (i.e., flow fields A, B, C, and K). The estimated TMI concentration exceeded its threshold for the low injection rate very rarely, and only out to a distance of 60 meters. Chloride and TMI threshold exceedances were limited almost exclusively to conditions involving the high injection rate or pressure. The slower velocity/lower flow ground-water settings permit less dilution (i.e., a higher probability of threshold exceedance) of constituents modeled for resource damage effects. In a trend similar to that observed for health risks,

waterflood wells were estimated to contaminate larger volumes of ground water than disposal wells under conditions involving casing failures, but disposal wells were estimated to contaminate larger volumes under conditions involving grout seal failures. Finally, the resource damage estimates for injection well failures (and also for reserve pit leachate) indicate that TMI is a greater contributor to ground-water contamination than chloride. The reason for this difference is that the mobile salts concentration in the model produced water waste stream is more than three times the chloride concentration (see Table V-1), while the resource damage thresholds differ by a factor of two (see Table V-2).

Potential Surface Water Damage

EPA examined the potential for surface water damage resulting from the influx of ground water contaminated by reserve pit seepage and injection well failures, as well as surface water damage resulting from direct discharge of stripper well produced water. For all model scenarios, EPA estimated the average annual surface water concentrations of waste constituents to be below their respective thresholds at the point where they enter the surface water; that is, the threshold concentrations for various waste constituents were not exceeded even at the point of maximum concentration in surface waters. This is because the input chemical mass is diluted substantially upon entering the surface water. Surface water usually flows at a much higher rate than ground water and also allows for more complete mixing than ground water. Both of these factor suggest that there will be greater dilution in surface water than in ground water. One would expect, therefore, that the low concentrations in ground water estimated for reserve pit seepage and injection well failures would be diluted even further upon seeping into surface water.

These limited modeling results do not imply that resource damage could not occur from larger releases, either through these or other migration pathways or from releases to lower flow surface waters (i.e., streams with flows below 40 ft^3/s). In addition, surface water damages could occur during short periods (less than a year) of low stream flow or peak waste discharge, which were not modeled in this study.

EPA analyzed what a river or stream flow rate would have to be (given the model produced water concentrations and discharge rates from stripper wells) in order for contaminant concentrations in the mixing zone (assuming instantaneous and complete mixing but not other removal processes) to exceed resource damage criteria. The results of this analysis are summarized in Table V-11. As shown, the maximum concentrations of chloride, boron, sodium, and TMI in streams or rivers caused by the discharge of produced water from stripper wells would (under most modeling conditions) not exceed resource damage criteria unless the receiving stream or river was flowing at a rate below 1 ft^3/s. The exceptions are scenarios with a conservative waste stream concentration and high discharge rate. If produced water was discharged to streams or rivers under these conditions, the maximum concentrations of sodium and TMI could exceed resource damage criteria in surface waters flowing up to 5 ft^3/s. (The maximum concentrations in any surface water flowing at a greater rate would not exceed the criteria.)

The results suggest that, if produced waters from stripper wells are discharged to streams and rivers under conditions that are similar to those modeled, resource damage criteria would be exceeded only in very small streams.

ASSESSMENT OF WASTE DISPOSAL ON ALASKA'S NORTH SLOPE

In accordance with the scope of the study required by RCRA Section 8002(m), this assessment addresses only the potential impacts associated

Table V-11 Surface Water Flow Rates At Which Concentrations of Waste Stream Constituents in the Mixing Zone Will Exceed Aquatic Effects and Resource Damage Thresholds[a]

Constituent	Concentration in waste	Waste stream discharge rate High (100 BPD)	Medium (10 BPD)	Low (1 BPD)
Sodium	Median	$\leq 0.7\ ft^3/s$[b]	$\leq 0.07\ ft^3/s$	$\leq 0.007\ ft^3/s$
	90th %	$\leq 5\ ft^3/s$	$\leq 0.5\ ft^3/s$	$\leq 0.05\ ft^3/s$
Chloride	Median	$\leq 0.2\ ft^3/s$	$\leq 0.02\ ft^3/s$	$\leq 0.002\ ft^3/s$
	90th %	$\leq 0.9\ ft^3/s$	$\leq 0.09\ ft^3/s$	$\leq 0.009\ ft^3/s$
Boron	Median	$\leq 0.06\ ft^3/s$	$\leq 0.006\ ft^3/s$	$\leq 0.0006\ ft^3/s$
	90th %	$\leq 0.8\ ft^3/s$	$\leq 0.08\ ft^3/s$	$\leq 0.008\ ft^3/s$
Total Mobile Ions	Median	$\leq 0.4\ ft^3/s$	$\leq 0.04\ ft^3/s$	$\leq 0.004\ ft^3/s$
	90th %	$\leq 2\ ft^3/s$	$\leq 0.2\ ft^3/s$	$\leq 0.02\ ft^3/s$

[a]The effect thresholds and effects considered in this analysis were as follows: Sodium-83 mg/L, which might result in toxic effects or osmoregulatory problems for freshwater aquatic organisms (note: while this threshold is based on toxicity data reported in the literature, it is dependent on several assumptions and is speculative); chloride--250 mg/L, which is EPA's secondary drinking water standard designed to prevent excess corrosion of pipes in hot water systems and to prevent objectionable tastes; boron--1 mg/L, which is a concentration in irrigation water that could damage sensitive crops (e.g., citrus trees; plum, pear, and apple trees; grapes; and avocados); and total mobile Ions--335 mg/L, which may be a tolerable level for freshwater species but would probably put them at a disadvantage in competing with brackish or marine organisms.

[b]Should be interpreted to mean that the concentration of sodium in the mixing zone would exceed the modeled effect threshold (described in footnote a) if the receiving stream or river was flowing at a rate of 0.7 ft^3/s or lower. If the stream or river was flowing at a higher rate, then the maximum concentration of sodium would not exceed the effect level.

with the management of exempt oil and gas wastes on Alaska's North Slope. It does not analyze risks or impacts from other activities, such as site development or road construction. The North Slope is addressed in a separate, qualitative assessment because readily available release and transport models for possible use in a quantitative assessment are not appropriate for many of the characteristics of the North Slope, such as the freeze-thaw cycle, the presence of permafrost, and the typical reserve pit designs.

Of the various wastes and waste management practices on the North Slope, it appears that the management of drilling waste in above-ground reserve pits has the greatest potential for adverse environmental effects. The potential for drilling wastes to cause adverse human health effects is small because the potential for human exposure is small. Virtually all produced water on the North Slope is reinjected approximately 6,000 to 9,000 feet below the land surface in accordance with discharge permits issued by the State of Alaska. The receiving formation is not an underground source of drinking water and is effectively sealed from the surface by permafrost. Consequently, the potential for environmental or human health impacts associated with produced fluids is very small under routine operating conditions.

During the summer thaw, reserve pit fluids are disposed of in underground injection wells, released directly onto the tundra or applied to roads if they meet quality restrictions specified in Alaska discharge permits, or stored in reserve pits. Underground injection of reserve pit fluids should have minor adverse effects for the same reasons as were noted above for produced waters. If reserve pit fluids are managed through the other approaches, however, there is much greater potential for adverse environmental effects.

Discharges of reserve pit fluids onto the tundra and roads are regulated by permits issued by the Alaska Department of Environmental Conservation (ADEC). In the past, reserve pit discharges have occasionally exceeded permit limitations for certain constituents. New permits, therefore, specify several pre-discharge requirements that must be met to help ensure that the discharge is carried out in an acceptable manner.

Only one U.S. Government study of the potential effects of reserve pit discharges on the North Slope is known to be complete. West and Snyder-Conn (1987), with the U.S. Fish and Wildlife Service, examined how reserve pit discharges in 1983 affected water quality and invertebrate communities in receiving tundra ponds and in hydrologically connected distant ponds. Although the nature of the data and the statistical analysis precluded a definitive determination of cause and effect, several constituents and characteristics (chromium, barium, arsenic, nickel, hardness, alkalinity, and turbidity) were found in elevated concentrations in receiving ponds when compared to control ponds. Also, alkalinity, chromium, and aliphatic hydrocarbons were elevated in hydrologically connected distant ponds when compared to controls. Accompanying these water quality variations was a decrease in invertebrate taxonomic richness, diversity, and abundance from control ponds to receiving ponds.

West and Snyder-Conn, however, cautioned that these results cannot be wholly extrapolated to present-day oil field practices on the North Slope because some industry practices have changed since 1983. For example, they state that "chrome lignosulfonate drill muds have been partly replaced by non-chrome lignosulfonates, and diesel oil has been largely replaced with less toxic mineral oil in drilling operations." Also, State regulations concerning reserve pit discharges have become increasingly stringent since the time the study was conducted. West and

Snyder-Conn additionally concluded that reserve pit discharges should be subject to standards for turbidity, alkalinity, chromium, arsenic, and barium to reduce the likelihood of biological impacts. ADEC's 1987 tundra discharge permit specifies effluent limitations for chromium, arsenic, barium, and several other inorganics, as well as an effluent limitation for settleable solids (which is related to turbidity). The 1987 permit requires monitoring for alkalinity, but does not specify an effluent limit for this parameter.

Reserve pits on the North Slope are frequently constructed above grade out of native soils and gravel. Below-grade structures are also built, generally at exploratory sites, and occasionally at newer production sites. Although the mud solids that settle at the bottom of the pits act as a barrier to fluid flow, fluids from above-ground reserve pits (when thawed) can seep through the pit walls and onto the tundra. No information was obtained on what percentage of the approximately 300 reserve pits on the North Slope are actually leaking; however, it has been documented that "some" pits do in fact seep (ARCO 1985, Standard Oil 1987). While such seepage is expected to be sufficiently concentrated to adversely affect soil, water, vegetation, and dependent fauna in areas surrounding the reserve pits, it is not known how large an area around the pits may be affected. Preliminary studies provided by industry sources indicate that seepage from North Slope reserve pits, designed and managed in accordance with existing State regulations, should not cause damage to vegetation more than 50 feet away from the pit walls (ARCO 1986, Standard Oil 1987). It is important to note that ADEC adopted regulations that should help to reduce the occurrence of reserve pit seepage and any impacts of drilling waste disposal. These regulations became effective in September 1987.

While some of the potentially toxic constituents in reserve pit liquids are known to bioaccumulate (i.e., be taken up by organisms low in

the food chain with subsequent accumulation in organisms higher in the food chain), there is no evidence to conclude that bioaccumulation from reserve pit discharge or seepage is occurring. In general, bioaccumulation is expected to be small because each spring thaw brings a large onrush of water that may help flush residual contamination, and higher level consumers are generally migratory and should not be exposed for extended periods. It is recognized, however, that tundra invertebrates constitute the major food source for many bird species on the Arctic coastal plain, particularly during the breeding and rearing seasons, which coincide with the period that tundra and road discharges occur. The Fish and Wildlife Service is in the process of investigating the effects of reserve pit fluids on invertebrates and birds, and these and other studies need to be completed before conclusions can be reached with respect to the occurrence of bioaccumulation on the North Slope.

With regard to the pit solids, the walls of operating pits have slumped on rare occasions, allowing mud and cuttings to spill onto the surrounding tundra. As long as these releases are promptly cleaned up, the adverse effects to vegetation, soil, and wildlife should be temporary (Pollen 1986, McKendrick 1986).

ADEC's new reserve pit closure regulations for the North Slope contain strengthened requirements for reserve pit solids to be dewatered, covered with earth materials, graded, and vegetated. The new regulations also require owners of reserve pits to continue monitoring and to maintain the cover for a minimum of 5 years after closure. If the reserve pit is constructed below grade such that the solids at closure are at least 2 feet below the bottom of the soil layer that thaws each spring, the solids will be kept permanently frozen (a phenomenon referred to as freezeback). The solids in closed above-grade pits will also undergo freezeback if they are covered with a sufficient layer of earth material to provide insulation. In cases where the solids are kept

permanently frozen, no leaching or erosion of the solid waste constituents should occur. However, ADEC's regulations do not require reserve pits to be closed in a manner that ensures freezeback. Therefore, some operators may choose to close their pits in a way that permits the solids to thaw during the spring. Even when the solids are not frozen, migration of the waste constituents will be inhibited by the reserve pit cover and the low rate of water infiltration through the solids. Nevertheless, in the long term, the cover could slump and allow increased snow accumulation in depressed areas. Melting of this snow could result in infiltration into the pit and subsequent leaching of the thawed solid waste contaminants. Also, for closed above-grade pits, long-term erosion of the cover could conceivably allow waste solids, if thawed, to migrate to surrounding areas. Periodic monitoring would forestall such possibilities.

LOCATIONS OF OIL AND GAS ACTIVITIES IN RELATION TO ENVIRONMENTS OF SPECIAL INTEREST

EPA analyzed the proximity of oil and gas activities to three categories of environments of special interest to the public: endangered and threatened species habitats, wetlands, and public lands. The results of this analysis are intended only to provide a rough approximation of the degree of and potential for overlap between oil and gas activities and these areas. The results should not be interpreted to mean that areas where oil and gas activities are located are necessarily adversely affected.

All of the 26 States having the highest levels of oil and gas activity are within the historical ranges of numerous endangered and threatened species habitats. However, of 190 counties across the U.S. identified as having high levels of exploration and production, only 13

(or 7 percent) have Federally designated critical habitats[10] within their boundaries. These 13 counties encompass the critical habitats for a total of 10 different species, or about 10 percent of the species for which critical habitats have been designated on the Federal level.

Wetlands create habitats for many forms of wildlife, purify natural waters by removing sediments and other contaminants, provide flood and storm damage protection, and afford a number of other benefits. In general, Alaska and Louisiana are the States with the most wetlands and oil and gas activity. Approximately 50 to 75 percent of the North Slope area consists of wetlands (Bergman et al. 1977). Wetlands are also abundant throughout Florida, but oil and gas activity is considerably less in that State and is concentrated primarily in the panhandle area. In addition, oil and gas activities in Illinois appear to be concentrated in areas with abundant wetlands. Other States with abundant wetlands (North Carolina, South Carolina, Georgia, New Jersey, Maine, and Minnesota) have very little onshore oil and gas activity.

For the purpose of this analysis, public lands are defined as the wide variety of land areas owned by the Federal Government and administered by the Bureau of Land Management (BLM), National Forest Service, or National Park Service. Any development on these lands must first pass through a formal environmental planning and review process. In many cases, these lands are not environmentally sensitive. National Forests, for example, are established for multiple uses, including timber development, mineral extraction, and the protection of environmental values. Public lands are included in this analysis, however, because they are considered "publicly sensitive," in the sense that they are commonly valued more highly by society than comparable areas outside

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10 Critical habitats, which are much smaller and more rigorously defined than historical ranges, are areas containing physical or biological factors essential to the conservation of the species.

their boundaries. The study focuses only on lands within the National Forest and National Park Systems because of recent public interest in oil and gas development in these areas (e.g., see Sierra Club 1986; Wilderness Society 1987).

The National Forest System comprises 282 National Forests, National Grasslands, and other areas and includes a total area of approximately 191 million acres. Federal oil and gas leases, for either exploration or production, have been granted for about 25 million acres (roughly 27 percent) of the system. Actual oil and gas activity is occurring on a much smaller acreage distributed across 11 units in eight States. More than 90 percent of current production on all National Forest System lands takes place in two units: the Little Missouri National Grassland in North Dakota and the Thunder Basin National Grassland in Wyoming.

The National Park System contains almost 80 million acres made up by 337 units and 30 affiliated areas. These units include national parks, preserves, monuments, recreation areas, seashores, and other areas. All units have been closed to future leasing of Federal minerals except for four national recreation areas where mineral leasing has been authorized by Congress and permitted under regulation. If deemed acceptable from an environmental standpoint, however, nonfederally owned minerals within a unit's boundaries can be leased.[11] Ten units (approximately 3 percent of the total) currently have active oil and gas operations within their boundaries. Approximately 23 percent of the land area made up by these ten units is currently under lease (approximately 256,000 acres); however, 83 percent of the area within the ten units (almost one million acres) is leasable. The National Park Service also has identified 32 additional units that do not have active oil and gas operations at present, but do have the potential for such activities in the future.

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[11] Nonfederally owned minerals within National Park System units exist where the Federal Government does not own all the land within a unit's boundaries or does not possess the subsurface mineral rights.

Several of these units also have acres that are under lease for oil and gas exploration, development, and production. In total, approximately 334,700 acres within the National Park System (or roughly 4 percent of the total) are currently under lease for oil and gas.

CONCLUSIONS

EPA's major conclusions, along with a summary of the main findings on which they are based, are listed below. EPA recognizes that the conclusions are limited by the lack of complete data and the necessary risk modeling assumptions. In particular, the limited amount of waste sampling data and the lack of empirical evidence on the probability of injection well failures have made it impossible to estimate precisely the absolute nationwide or regional risks from current waste management practices for oil and gas wastes. Nevertheless, EPA believes that the risk analysis presented here has yielded many useful conclusions relating to the nature of potential risks and the circumstances under which they are likely to occur.

General Conclusions

- For the vast majority of model scenarios evaluated in this study, only very small to negligible risks would be expected to occur even if the toxic chemical(s) of concern were of relatively high concentration in the wastes and there was a release into ground water as was assumed in this analysis. Nonetheless, the model results also show that there are realistic combinations of measured chemical concentrations (at the 90th percentile level) and release scenarios that could be of substantial concern. EPA cautions that there are other release modes not considered in this analysis that could also contribute to risks. In addition, there are almost certainly toxic contaminants in the large unsampled population of reserve pits and produced fluids that could exceed concentration levels measured in the relatively small number of waste samples analyzed by EPA.

- EPA's modeling of resource damages to surface water--both in terms of ecological impact and of resource degradation--generally did not show significant risk. This was true both for ground-water seepage and direct surface water discharge (from stripper wells) pathways for drilling pit and produced water waste streams. This conclusion holds for the range of receiving water flow rates modeled, which included only moderate (40 ft^3/s) to large (850 ft^3/s) streams. It is clear that potential damages to smaller streams would be quite sensitive to relative discharge or ground-water seepage rates.

- Of the hundreds of chemical constituents detected in both reserve pits and produced water, only a few from either source appear to be of primary concern relative to health or environmental damages. Based on an analysis of toxicological data, the frequency and measured concentrations of waste constituents in the relatively small number of sampled waste streams, and the mobility of these constituents in ground water, EPA found a limited number of constituents to be of primary relevance in the assessment of risks via ground water. Based on current data and analysis, these constituents include arsenic, benzene, sodium, chloride, cadmium, chromium, boron, and mobile salts. All of these constituents were included in the quantitative risk modeling in this study. Cadmium, chromium, and boron did not produce risks or resource damages under the conditions modeled. Note: This conclusion is qualified by the small number of sampled sites for which waste composition could be evaluated.

- Both for reserve pit waste and produced water, there is a very wide (six or more orders of magnitude) variation in estimated health risks across scenarios, depending on the different combinations of key variables influencing the individual scenarios. These variables include concentrations of toxic chemicals in the waste, hydrogeologic parameters, waste amounts and management practices, and distance to exposure points.

Drilling Wastes Disposed of in Onsite Reserve Pits

- Most of the 1,134 onsite reserve pit scenarios had very small or no risks to human health via ground-water contamination of drinking water for the conditions modeled. Under the best-estimate assumptions, there were no carcinogenic waste constituents modeled (median concentrations for carcinogens in the EPA samples were zero or below detection), and more than 99 percent of the nationally weighted reserve pit scenarios resulted in exposure to noncarcinogens (sodium, cadmium, chromium)

at concentration levels below health effect thresholds. Under more conservative assumptions, including toxic constituents at 90th percentile sample concentrations, no scenarios evaluated yielded lifetime cancer risks as high as 1 in 100,000 (1×10^{-5}),[12] and only 2 percent of the nationally weighted conservative scenarios showed cancer risks greater than 1×10^{-7}. Noncancer risks were estimated by threshold exceedances for only 2 percent of nationally weighted scenarios, even when the 90th percentile concentration of sodium in the waste stream was assumed. The maximum sodium concentration at drinking water wells was estimated to be roughly 32 times the threshold for hypertension. In general, these modeling results suggest that most onsite reserve pits will present very low risks to human health through ground-water exposure pathways.

- It appears that people may be able to taste chloride in the drinking water in those scenarios with the highest cancer and noncancer risks. It is questionable, however, whether people would actually discontinue drinking water containing these elevated chloride concentrations.

- Weighting the risk results to account for different distributions of hydrogeologic variables, pit size, and exposure distance across geographic zones resulted in limited variability in risks across zones. Risk distributions for individual zones generally did not differ from the national distribution by more than one order of magnitude, except for zones 10 (West Coast) and 11B (Alaska, non-North Slope), which usually were extremely low. Note: EPA was unable to develop geographical comparisons of toxic constituent concentrations in drilling pit wastes.

- Several factors were evaluated for their individual effects on risk. Of these factors, ground-water flow field type and exposure distance had the greatest influence (several orders of magnitude); recharge rate, subsurface permeability, and pit size had less, but measurable, influence (approximately one order of magnitude). Typically, the higher risk cases occur in the context of the largest unlined pits, the short (60-meter) exposure distance, and high subsurface permeability and infiltration. Depth to ground water and presence/absence of a single synthetic liner had virtually no measurable influence over the 200-year modeling period; however, risk estimated over shorter time periods, such as 50 years, would likely be lower for lined pits compared to unlined pits, and lower for deep ground water compared to shallow ground water.

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12 A cancer risk estimate of 1×10^{-5} indicates that the chance of an individual contracting cancer over a 70-year average lifetime is approximately 1 in 100,000. The Agency establishes the cutoff between acceptable and unacceptable levels of cancer risk between 1×10^{-7} and 1×10^{-4}.

- Estimated ground-water resource damage (caused by exceedance of water quality thresholds for chloride and total mobile ions) was very limited and essentially confined to the closest modeling distance (60 meters). These resource damage estimates apply only to the pathway modeled (leaching through the bottom of onsite pits) and not to other mechanisms of potential ground-water contamination at drilling sites, such as spills or intentional surface releases.

- No surface water resource damage (caused by exceedance of thresholds for chloride, sodium, cadmium, chromium VI, or total mobile ions) was predicted for the seepage of leachate-contaminated ground water into flowing surface water. This finding, based on limited modeling, does not imply that resource damage could not occur from larger releases, either through this or other pathways of migration, or from releases to lower flow surface waters (below 40 ft^3/s).

Produced Water Disposal in Injection Wells

- All risk results for underground injection presented in this chapter assume that either a grout seal or well casing failure occurs. However, as anticipated under EPA's Underground Injection Control (UIC) regulatory program, these failures are probably low-frequency events, and the actual risks resulting from grout seal and casing failures are expected to be much lower than the conditional risks presented here. The results do not, however, reflect other possible release pathways such as migration through unplugged boreholes or fractures in confining layers, which also could be of concern.

- Only a very small minority of injection well scenarios resulted in meaningful risks to human health, due to either grout seal or casing failure modes of release of produced water to drinking water sources. In terms of carcinogenic risks, none of the best-estimate scenarios (median arsenic and benzene sample concentrations) yielded lifetime risks greater than 5 per 1,000,000 (5×10^{-6}) to the maximally exposed individual. When the 90th percentile benzene and arsenic concentrations were examined, a maximum of 35 percent of EPA's nationally weighted scenarios had risks greater than 1×10^{-7}, with up to 5 percent having cancer risks greater than 1×10^{-4} (the highest risk was 9×10^{-4}). The high cancer risk scenarios corresponded to a very short (60-meter) exposure distance combined with relatively high injection pressure/rates and a few specific ground-water flow fields (fields C and D in Table V-7).

- Noncancer health effects modeled were limited to hypertension in sensitive individuals caused by ingestion of sodium in drinking water. In the best-estimate scenarios, up to 8 percent of EPA's nationally weighted scenarios had threshold exceedances for sodium in ground-water supplies. In the conservative scenarios, where 90th percentile sodium concentrations were assumed in the injection waters, threshold exceedances in drinking water were predicted for a maximum of 22 percent of the nationally weighted scenarios. The highest sodium concentration predicted at exposure wells under conservative assumptions exceeded the threshold for hypertension by a factor of 70. The high noncancer risk scenarios corresponded to a very short (60-meter) exposure distance, high injection pressures/rates, and relatively slow ground-water velocities/low flows.

- It appears that people would not taste or smell chloride or benzene at the concentration levels estimated for the highest cancer risk scenarios, but sensitive individuals would be more likely to detect chloride or benzene tastes or odors in those scenarios with the highest noncancer risks. It is questionable, however, whether the detectable tastes or smells at these levels would generally be sufficient to discourage use of the water supply.

- As with the reserve pit risk modeling results, adjusting (weighting) the injection well results to account for differences among various geographic zones resulted in relatively small differences in risk distributions. Again, this lack of substantial variability in risk across zones may be the result of limitations of the study approach and the fact that geographic comparisons of toxic constituents in produced water was not possible.

- Of several factors evaluated for their effect on risk, exposure distance and ground-water flow field type had the greatest influence (two to three orders of magnitude). Flow rate/pressure had less, but measurable, influence (approximately one order of magnitude). Injection well type (i.e., waterflood vs. disposal) had moderate but contradictory effects on the risk results. For casing failures, high-pressure waterflood wells were estimated to cause health risks that were about 2 times higher than the risks from lower pressure disposal wells under otherwise similar conditions. However, for grout seal failures, the risks associated with disposal wells were estimated to be up to 3 times higher than the risks in similar circumstances associated with waterflood wells, caused by the higher injection rates for disposal.

- Estimated ground-water resource damage (resulting from exceedance of thresholds for chloride, boron, and total mobile ions) was extremely limited and was essentially confined to the 60-meter modeling distance. This conclusion applies only to releases from Class II injection wells, and not to other mechanisms of potential ground-water contamination at oil and gas production sites (e.g., seepage through abandoned boreholes or fractures in confining layers, leaching from brine pits, spills).

- No surface water resource damage (resulting from exceedance of thresholds for chloride, sodium, boron, and total mobile ions) was predicted for seepage into flowing surface water of ground water contaminated by direct releases from injection wells. This finding does not imply that resource damage could not occur via mechanisms and pathways not covered by this limited surface water modeling, or in extremely low flow streams.

Stripper Well Produced Water Discharged Directly into Surface Water

- Under conservative modeling assumptions, 17 percent of scenarios (unweighted) had cancer risks greater than 1×10^{-5} (the maximum cancer risk estimate was roughly 4×10^{-5}).[13] The maximum cancer risk under best-estimate waste stream assumptions was 4×10^{-7}. No exceedances of noncancer effect thresholds or surface water resource damage thresholds were predicted under any of the conditions modeled. The limited surface water modeling performed applies only to scenarios with moderate- to high-flow streams (40 to 850 ft^3/s). Preliminary analyses indicate, however, that resource damage criteria would generally be exceeded in only very small streams (i.e., those flowing at less than 5 ft^3/s), given the sampled waste stream chemical concentrations and discharge rates for stripper wells of up to 100 barrels per day.

Drilling and Production Wastes Managed on Alaska's North Slope

- Adverse effects to human health are expected to be negligible or nonexistent because the potential for human exposure to drilling waste and produced fluid contaminants on the North Slope is very small. The greatest potential for adverse environmental impacts is caused by discharge and seepage of reserve pit fluids containing toxic substances onto the tundra. A field study conducted in 1983 by the U.S. Fish and Wildlife Service indicates that tundra discharges of reserve pit fluids may adversely affect water quality and invertebrates in surrounding areas; however, the

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13 These results are unweighted because the frequency of occurrence of the parameters that define the stripper well scenarios was not estimated.

results of this study cannot be wholly extrapolated to present-day practices on the North Slope because some industry practices have changed and State regulations concerning reserve pit discharges have become increasingly more stringent since 1983. Preliminary studies from industry sources indicate that seepage from operating above-ground reserve pits on the North Slope may damage vegetation within a radius of 50 feet. The Fish and Wildlife Service is in the process of studying the effects of reserve pit fluids on tundra organisms, and these studies need to be completed before more definitive conclusions can be made with respect to environmental impacts on the North Slope.

Locations of Oil and Gas Activities in Relation to Environments of Special Interest

- All of the top 26 States that have the highest levels of onshore oil and gas activity are within the historical ranges of numerous endangered and threatened species habitats; however, of 190 counties identified as having high levels of exploration and production, only 13 (or 7 percent) have federally designated critical habitats for endangered species within their boundaries. The greatest potential for overlap between onshore oil and gas activities and wetlands appears to be in Alaska (particularly the North Slope), Louisiana, and Illinois. Other States with abundant wetlands have very little onshore oil and gas activity. Any development on public lands must first pass through a formal environmental review process and some public lands, such as National Forests, are managed for multiple uses including oil and gas development. Federal oil and gas leases have been granted for approximately 25 million acres (roughly 27 percent) of the National Forest System. All units of the National Park System have been closed to future leasing of federally owned minerals except for 4 National Recreation Areas where mineral leasing has been authorized by Congress. If deemed acceptable from an environmental standpoint, however, nonfederally owned minerals within the park boundaries can be leased. In total, approximately 4 percent of the land area in the National Park System is currently under lease for oil and gas activity.

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CHAPTER VI

COSTS AND ECONOMIC IMPACTS OF ALTERNATIVE WASTE MANAGEMENT PRACTICES

OVERVIEW OF THE COST AND ECONOMIC IMPACT ANALYSIS

This chapter provides estimates of the cost and selected economic impacts of implementing alternative waste management practices by the oil and gas industry. The industry's current or "baseline" practices are described in Chapter III. In addition to current practices, a number of alternatives are available. Some of these offer the potential for higher levels of environmental control. Section 8002(m) of RCRA requires an assessment of the cost and impact of these alternatives on oil and gas exploration, development, and production.

This chapter begins by providing cost estimates for baseline and alternative waste management practices. The most prevalent current practices are reserve pit storage and disposal for drilling wastes and Class II deep well injection for produced water. In addition, several other waste management practices are included in the cost evaluation. The cost estimates for the baseline and alternative waste management practices are presented as the cost per unit of waste disposal (e.g., cost per barrel of drilling waste, cost per barrel of produced water). These unit cost estimates allow for a comparison among disposal methods and are used as input information for the economic impact analysis.

After establishing the cost of baseline and alternative practices on a unit-of-waste basis, the chapter expands its focus to assess the impact of higher waste management costs both on individual oil and gas projects and on the industry as a whole. For the purpose of this assessment, three hypothetical regulatory scenarios for waste management are defined. Each scenario specifies a distinct set of alternative environmentally protective waste management practices for

oil and gas projects that generate potentially hazardous waste. Projects that do not generate hazardous waste may continue to use baseline practices under this approach.

After the three waste management scenarios have been defined, the remainder of the chapter provides estimates of their cost and economic impact. First, the impact of each scenario on the capital and operating cost and on the rate of return for representative new oil and gas projects is estimated. Using these cost estimates for individual projects as a basis, the chapter then presents regional- and national-level cost estimates for the waste management scenarios.

The chapter then describes the impact of the waste management scenarios on existing projects (i.e., projects that are already in production). It provides estimates of the number of wells and the amount of current production that would be shut down as a result of imposing alternative waste management practices under each scenario. Finally, the chapter provides estimates of the long-term decline in domestic production brought about by the costs of the waste management scenarios and estimates of the impact of that decline on the U.S. balance of payments, State and Federal revenues, and other selected economic aggregates.

The analysis presented in this chapter is based on the information available to EPA in November 1987. Although much new waste generation and waste management data was made available to this study, both by EPA and the American Petroleum Institute, certain data limitations did restrict the level of analysis and results. In particular, data on waste generation, management practices, and other important economic parameters were generally available only in terms of statewide or nationwide

averages. Largely because of this, the cost study was conducted using "average regional projects" as the basic production unit of analysis. This lack of desired detail could obscure special attributes of both marginal and above average projects, thus biasing certain impact effects, such as the number of well closures.

The scope of the study was also somewhat limited in other respects. For example, not all potential costs of alternative waste management under the RCRA amendments could be evaluated, most notably the land ban and corrective action regulations currently under development. The Agency recognizes that this could substantially understate potential costs of some of the regulatory scenarios studied. The analysis was able to distinguish separately between underground injection of produced water for disposal purposes and injection for waterflooding as a secondary or enhanced energy recovery method. However, it was not possible during the course of preparing this report to evaluate the costs or impacts of alternative waste management regulations on tertiary (chemical, thermal, and other advanced EOR) recovery, which is becoming an increasingly important feature of future U.S. oil and gas production.

COST OF BASELINE AND ALTERNATIVE WASTE MANAGEMENT PRACTICES

Identification of Waste Management Practices

The predominant waste management practices currently employed by the oil and gas industry are described in Chapter III of this report. For drilling operations, wastes are typically stored in an unlined surface impoundment during drilling. After drilling, the wastes are dewatered, either by evaporation or vacuum truck, and buried onsite. Where vacuum trucks are used for dewatering, the fluids are removed for offsite

disposal, typically in a Class II injection well. For production operations, the predominant disposal options are injection into a Class II onsite well or transportation to an offsite Class II disposal facility. Where onsite injection is used, the Class II well may be used for disposal only or it may be used to maintain pressure in the reservoir for enhanced oil recovery.

In addition to the above disposal options, a number of additional practices are considered here. Some of these options are fairly common (Table VI-1). For example, 37 percent of current drill sites use a lined disposal pit; 12 percent of production sites in the lower 48 States (Lower 48) discharge their produced water to the surface. Other disposal options considered here (e.g., incineration) are not employed to any significant extent at present.

For drilling waste disposal, nine alternative practices were reviewed for the purpose of estimating comparative unit costs and evaluating subsequent cost-effectiveness in complying with alternative regulatory options:

1. Onsite unlined surface impoundment;
2. Onsite single-synthetic-liner surface impoundment;
3. Offsite single-synthetic-liner surface impoundment;
4. Offsite synthetic composite liner with leachate collection (SCLC), Subtitle C design;
5. Landfarming consistent with current State oil and gas field regulations;
6. Landfarming consistent with RCRA Subtitle C requirements;
7. Waste solidification;
8. Incineration; and
9. Volume reduction.

Table VI-1 Summary of Baseline Disposal Practices, by Zone, 1985

Zone	Drilling waste disposal (percent of drill sites)		Produced water disposition (percent of produced waters)		
				Class II Injection	
	Unlined facilities	Lined facilities	Surface discharge	EOR	Disposal
Appalachian	23	77	50	25	25
Gulf	89	11	34	11	55
Midwest	47	53	0	91	9
Plains	49	51	0	38	62
Texas/ Oklahoma	60	40	4	69	27
Northern Mountain	65	35	12	45	42
Southern Mountain	50	50	0	84	16
West Coast	99	1	23	54	23
Alaska	67	33	0	71	29
Total U.S.	63	37	11	59	28
Lower 48 States	63	37	12	60	28

Sources: Drilling waste and produced water disposal information from API, 1987a except for produced water disposal percents for the Appalachian zone, which are based on personal communications with regional industry sources.

NOTE: Produced water disposition percents for total U.S. and Lower 48 are based on survey sample weights. Weighting by oil production results in a figure of 9 percent discharge in the Lower 48 (API 1987b).

In addition to these disposal options, costs were also estimated for ground-water monitoring and general site management for waste disposal sites. These latter practices can be necessary adjunct requirements for various final disposal options to enhance environmental protection.

For produced water, two alternative practices were considered in the cost analysis: Class I injection wells and Class II injection wells. Both classes may be used for water disposal or for enhanced energy recovery waterflooding. They may be located either onsite or, in the case of disposal wells, offsite. To depict the variation in use patterns of these wells, cost estimates were developed for a wide range of injection capacities.

Cost of Waste Management Practices

For each waste disposal option, engineering design parameters of representative waste management facilities were established for the purpose of costing (Table VI-2). For the baseline disposal methods, parameters were selected to typify current practices. For waste management practices that achieve a higher level of environmental control than the most common baseline practices, parameters were selected to typify the best (i.e., most environmentally protective) current design practices. For waste management practices that would be acceptable for hazardous waste under Subtitle C of RCRA, parameters were selected to represent compliance with these regulations as they existed in early 1987.

Capital and operating and maintenance (O&M) costs were estimated for each waste management practice based on previous EPA engineering cost documents and tailored computer model runs, original contractor engineering cost estimates, vendor quotations, and other sources.[1] Capital costs were annualized using an 8 percent discount rate, the

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1 See footnotes to Tables VI-3 and VI-4 and Eastern Research Group 1987 for a detailed source list.

Table VI-2 Summary of Engineering Design Elements for Baseline and Alternative Waste Management Practices

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Unlined pit	• Pit excavation (0.25 acre) • Clearing and grubbing • Contingency • Contractor fee	• Negligible	• Pit burial (earth fill only) • Contingency • Contractor fee	
One-liner pit (waste buried on site)	• Clearing and grubbing • Pit excavation (0.25 acre) • Berm construction (gravel and vegetation) • 30-mil synthetic liner • Liner protection (geotextile subliner) • Engineering, contractor, and inspection fee • Contingency	• Negligible	• Pit burial (earth fill) • Capping - 30-mil PVC synthetic membrane - topsoil • Revegetation • Engineering, contractor, and inspection fee • Contingency	
Offsite one-liner facility	• Pit excavation (15 acres) • Same costs as onsite one-liner pit with addition of: - land cost - utility site work - pumps - spare parts - dredging equipment - inlet/outlet structures - construction and field expense	• Operating labor - clerical staff - foremen • Maintenance labor and supplies • Utilities • Plant overhead • Dredging	• Same costs as onsite one-liner pit • Solidification • Free liquid removal and treatment	

Table VI-2 (continued)

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Offsite SCLC facility	• Pit excavation (15 acres) • Same costs as commercial one-liner pit with the addition of: - additional pit liners - clay liner replaces geotextile subliner	• Same costs as commercial one-liner pit	• Same costs as onsite one-liner pit with addition of synthetic cap • Equipment decontamination	(See ground-water monitoring and site management)
Ground water monitoring and site management	• Ground-water monitoring wells • Leachate collection system - drainage tiles - leachate collection layer (sand or gravel) for single-liner case only - leachate collection liner for single-liner case only • Signs/fencing • RCRA permitting (for RCRA scenario)	• Ground-water monitoring wells sampling and laboratory fees • Leachate treatment	• Soil poisoning (to prevent disruption by long-rooted plants) • Cover drainage tile - collection layer (sand or gravel) - geotextile filter fabric in one-liner pit • Monitoring • Certification, supervision	• Monitoring well sampling • Leachate treatment • Notice to local authorities • Notation on property deed • Facility inspection • Maintenance and repair • Cover replacement • Engineering and inspection fees • Contingency
Offsite, multiple-application landfarming	• Land cost • Land clearing cost • Building cost • Lysimeter cost (RCRA scenario) • Cluster wells (RCRA scenario)	• Labor • Ground-water monitoring • Soil core cost • Maintenance • Utilities • Insurance, taxes, and G & A	• Revegetation • Testing	• Land authority and property deed cost • Ground-water monitoring cost • Soil core cost • Erosion control cost • Vegetative cover cost

Table VI-2 (continued)

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Offsite, multiple-application landfarming (continued)	• Wind dispersal control (RCRA scenario) • Storage tanks • Engineering and inspection • Contingency • Retention pond (RCRA scenario) • Berms (RCRA scenario)			• Engineering and inspection costs • Contingency
Volume reduction	• Equipment rental - mechanical or vacuum separation equipment • Tanks	• Chemicals • Labor		
Injection (Class II)	• Convert existing well to disposal well - completion rig contract - drilling fluids - cementing - logging and perforating - stimulation - liner and tubing • Site work/building • Holding tanks • Skim tanks • Filters and pumps • Pipelines	• Labor • Chemicals • Electricity • Filters • Disposal of filtrates • Pump maintenance • Pressure tests • Liability costs	• Plug and abandon	

Table VI-2 (continued)

Alternative	Capital costs	O & M costs	Closure costs	Post-closure costs
Injection (Class I)	• Drill new well - drilling rig contract - completion rig contract - cementing - logging and perforating - site preparation - casing - liner - tubing • Storage tanks • Annular fluid tank • Filters • Pumps • Pipelines • Site work/buildings • RCRA permit cost (RCRA scenario)	• Same costs as Class II wells with addition of: - tracer survey - cement bond log - pipe evaluation - disposal of filtrate in hazardous waste facility	• Plug and abandon	

approximate after-tax real cost of capital for this industry. Annualized capital costs were then added to O&M costs to compute the total annual costs for typical waste management unit operations. Annual costs were divided by annual waste-handling capacity (in barrels) to provide a cost per barrel of waste disposal. Both produced water disposal costs and drilling waste (i.e., muds and cuttings) disposal costs are expressed on a dollars-per-barrel basis.

The average engineering unit cost estimates for drilling wastes are presented in Table VI-3 for each region and for a composite of the Lower 48. Regional cost variations were estimated based on varying land, construction, and labor costs among regions. The costs for the Lower 48 composite are estimated by weighting regional cost estimates by the proportion of production occurring in each region. (Throughout the discussion that follows, the Lower 48 composite will be referenced to illustrate the costs and impacts in question.)

For the Lower 48 composite, the drilling waste disposal cost estimates presented in Table VI-3 range from $2.04 per barrel for onsite, unlined pit disposal to $157.50 per barrel for incineration. Costs for the disposal options are significantly higher for Alaska because of the extreme weather conditions, long transportation distances from population and material centers to drill sites, high labor costs, and other unique features of this region.

Costs for produced water are presented in Table VI-4. Disposal costs include injection costs, as well as transport, loading, and unloading charges, where appropriate. Injection for EOR purposes occurs onsite in either Class II or Class I wells. Class II disposal occurs onsite in all zones except Appalachia. Class I disposal occurs offsite except for the Northern Mountain and Alaska zones. Well capacities and transport distances vary regionally depending on the volume of water production and the area under production.

Table VI-3 Unit Costs of Drilling Waste Disposal Options, by Zone (Dollars per Barrel of Waste, 1985 Basis)

Disposal option	Zone: Appalachian	Gulf	Midwest	Plains	Texas/ Oklahoma	Northern Mountain	Southern Mountain	West Coast	Alaska	Lower 48
Surface impoundment[a]										
Unlined (0.25 acre)	$ 2.09	$ 1.98	$ 2.00	$ 1.98	$ 2.10	$ 2.00	$ 2.00	$ 2.04	$ 2.69	$ 2.04
Single-liner (0.25 acre)	4.62	4.32	4.35	4.29	4.63	4.35	4.35	4.46	6.16	4.46
SCLC (15 acres)	18.26	12.41	25.61	19.54	11.66	19.73	20.69	27.54	20.27	15.52
Landfarming[b]										
Current	13.21	12.06	12.41	15.91	17.01	16.14	15.99	16.42	N.E.	15.47
Subtitle C	30.23	31.58	28.94	39.14	40.31	36.45	36.38	38.45	N.E.	37.12
Solidification[c]	8.00	8.00	8.00	8.00	8.00	8.00	8.00	8.00	N.E.	8.00
Incineration[d]	157.50	157.50	157.50	157.50	157.50	157.50	157.50	157.50	N.E.	157.50
Volume reduction and offsite single-liner disposal[e]	15.16	3.18	17.24	9.50	5.83	5.40	6.15	21.87	5.67	6.74
Volume reduction and offsite SCLC disposal[e]	19.27	7.94	25.50	15.94	9.91	11.90	12.93	30.71	12.57	11.95

N.E. = Not estimated; disposal method not practical and/or information not available for Alaska.

[a]Source: Pope Reid Associates 1985a, 1985b, 1987a; costs for SCLC disposal include transportation charges.
[b]Source: Pope Reid Associates 1987b.
[c]Source: Erlandson 1986; Webster 1987; Tesar 1986; Camp, Dresser & McKee 1986; Hanson and Jones 1986; Cullinane et al. 1986; North American Environmental Service 1985.
[d]Source: USEPA 1986.
[e]Source: Slaughter 1987; Rafferty 1987. Costs include equipment rental and transport and disposal of reduced volume of waste. All costs are allocated over the original volume of waste so that per-barrel costs of waste disposal are comparable to the other cost estimates in the table.

Table VI-4 Unit Costs of Underground Injection of Produced Water, by Zone (Dollars per Barrel of Water)

Zone	Class II injection Disposal	Class II injection EOR	Class I injection[a] Disposal	Class I injection[a] EOR
Appalachian[b]	$1.26-1.33	$0.75	$2.45	$6.12
Gulf	0.10	0.23	0.84	1.35
Midwest	0.29	0.13	1.14	0.84
Plains	0.14	0.19	0.86	1.21
Texas/Oklahoma	0.11	0.14	0.96	0.76
Northern Mountain	0.01	0.14	0.40	0.58
Southern Mountain	0.07	0.14	1.05	0.67
West Coast	0.04	0.05	0.72	0.25
Alaska	0.05	0.41	1.28	2.15
Lower 48 States	0.10	0.14	0.92	0.78

[a] Disposal costs for Class I injection include transportation and loading/unloading charges except for the Northern Mountain zone and Alaska, where onsite disposal is expected to occur.

[b] Class II disposal costs for Appalachian zone includes transport and loading/unloading charges. Lower estimate is for intermediate scenarios; higher estimate is for baseline practice due to change in transport distances. For all other zones, Class II disposal is assumed to occur onsite.

Sources: Tilden 1987a, 1987b.

NOTE: Base year for costs is 1985.

Produced water disposal costs range from $0.01 to $1.33 per barrel for Class II disposal and EOR injection and from $0.40 to $6.12 per barrel for Class I disposal and EOR injection. Costs for Class I facilities are substantially higher because of the increased drilling completion, monitoring, and surface equipment costs associated with waste management facilities that accept hazardous waste.

The transportation of waste represents an additional waste management cost for some facilities. Transportation of drilling or production waste for offsite centralized or commercial disposal is practiced now by some companies and has been included as a potential disposal option in the waste management scenarios. Drilling waste transport costs range from $0.02 per barrel/mile for nonhazardous waste to $0.06 per barrel/mile for hazardous waste. Produced water transport costs range from $0.01 per barrel/mile (nonhazardous) to $0.04 per barrel/mile (hazardous). Distances to disposal facilities were estimated based on the volume of wastes produced, facility capacities, and the area served by each facility. Waste transportation also involves costs for loading and unloading.

WASTE MANAGEMENT SCENARIOS AND APPLICABLE WASTE MANAGEMENT PRACTICES

In order to determine the potential costs and impacts of changes in oil and gas waste disposal requirements, three waste management scenarios have been defined. The scenarios have been designed to illustrate the cost and impact of two hypothetical additional levels of environmental control in relation to current baseline practices. EPA has not yet identified, defined, or evaluated its regulatory options for the oil and gas industry; therefore, it should be noted that these scenarios <u>do not</u> represent regulatory determinations by EPA. A regulatory determination will be made by EPA following the Report to Congress.

Baseline Scenario

The Baseline Scenario represents the current situation. It encompasses the principal waste management practices now permitted under State and Federal regulations. Several key features of current practice for both drilling waste and produced water were summarized in Table VI-1, and the distribution of disposal practices shown in Table VI-1 is the baseline assumption for this analysis.

Intermediate Scenario

The Intermediate Scenario depicts a higher level of control. Operators generating wastes designated as hazardous are subject to requirements more stringent than those in the Baseline Scenario. An exact definition of "hazardous" has not been formulated for this scenario. Further, even if a definition were posited (e.g., failure of the E.P. toxicity test), available data are insufficient to determine the proportion of the industry's wastes that would fail any given test. Pending an exact regulatory definition of "hazardous" and the development of better analytical data, a range of alternative assumptions has been employed in the analysis. In the Intermediate 10% Scenario, the Agency assumed, for the purpose of costing, that 10 percent of oil and gas projects generate hazardous waste and in the Intermediate 70% Scenario that 70 percent of oil and gas projects generate hazardous waste.

For drilling wastes designated hazardous, operators would be required to use a single-synthetic-liner facility, landfarming with site management (as defined in Table VI-2), solidification, or incineration. Operators would select from these available compliance measures on the basis of lowest cost. Since a substantial number of operators now employ a single synthetic liner in drilling pits, only those sites not using a liner would be potentially affected by the drilling waste requirements of the Intermediate Scenario.

For produced waters, the Intermediate Scenario assumes injection into Class II facilities for any produced water that is designated hazardous. Operators now discharging waste directly to water or land (approximately 9 to 12 percent of all water) would be required to use a Class II facility if their wastes were determined to be hazardous.

"Affected operations" under a given scenario are those oil and gas projects that would have to alter their waste management practices and incur costs to comply with the requirements of the scenario. For example, in the Intermediate 10% Scenario, it is assumed that only 10 percent of oil and gas projects generate hazardous waste. For drilling, an estimated 63 percent of oil and gas projects now use unlined facilities and are therefore potentially affected by the requirements of the scenario. Since 10 percent of these projects are assumed to generate hazardous waste, an estimated 6.3 percent of the projects are affected operations, which are subject to higher disposal costs.

The Subtitle C Scenario

In the Subtitle C Scenario, wastes designated as hazardous are subject to pollution control requirements consistent with Subtitle C of RCRA. For drilling wastes, those wastes that are defined as hazardous must be disposed of in a synthetic composite liner with leachate collection (SCLC) facility employing site management and ground-water monitoring practices consistent with RCRA Subtitle C, a landfarming facility employing Subtitle C site management practices, or a hazardous waste incinerator. In estimating compliance costs EPA estimated that a combination of volume reduction and offsite dedicated SCLC disposal would be the least-cost method for disposal of drilling waste. For production wastes, those defined as hazardous must be injected into Class I disposal or EOR injection wells.

Since virtually no drilling or production operations currently use Subtitle C facilities or Class I injection wells in the baseline, all projects that generate produced water are potentially affected. In the Subtitle C 10% Scenario, 10 percent of these projects are assumed to be affected; in the Subtitle C 70% Scenario, 70 percent of these projects are affected. The Subtitle C Scenario, like the Intermediate Scenario, does not establish a formal definition of "hazardous"; nor does it attempt to estimate the proportion of wastes that would be hazardous under the scenario. As with the Intermediate Scenario, two assumptions (10 percent hazardous, 70 percent hazardous) are employed, and a range of costs and impacts is presented.

This Subtitle C Scenario does not, however, impose all possible technological requirements of the Solid Waste Act Amendments, such as the land ban and corrective action requirements of the Hazardous Solid Waste Amendments (HSWA), for which regulatory proposals are currently under development in the Office of Solid Waste. Although the specific regulatory requirements and their possible applications to oil and gas field practices, especially deep well injection practices, were not sufficiently developed to provide sufficient guidelines for cost evaluation in this report, the Agency recognizes that the full application of these future regulations could substantially increase the costs and impacts estimated for the Subtitle C Scenario.

The Subtitle C-1 Scenario

The Subtitle C-1 Scenario is exactly the same as the Subtitle C Scenario, except that produced water used in waterfloods is considered part of a production process and is therefore exempt from more stringent (i.e., Class I) control requirements, even if the water is hazardous. As shown in Table VI-1, approximately 60 percent of all produced water is used in waterfloods. Thus, only about 40 percent of produced water is potentially affected under the Subtitle C-1 Scenario. The requirements

of the Subtitle C-1 Scenario for drilling wastes are exactly the same as those of the Subtitle C Scenario. As with the other scenarios, alternative assumptions of 10 and 70 percent hazardous are employed in the Subtitle C-1 Scenario.

Summary of Waste Management Scenarios

Table VI-5 summarizes the major features of all the waste management scenarios. It identifies acceptable disposal practices under each scenario and the percent of wastes affected under each scenario. The Subtitle C 70% Scenario enforces the highest level of environmental control in waste management practices, and it affects the largest percent of facilities.

COST AND IMPACT OF THE WASTE MANAGEMENT SCENARIOS FOR TYPICAL NEW OIL AND GAS PROJECTS

Economic Models

An economic simulation model, developed by Eastern Research Group (ERG) and detailed in the Technical Background Document (ERG 1987), was employed to analyze the impact of waste management costs on new oil and gas projects. The economic model simulates the performance and measures the profitability of oil and gas exploration and development projects both before and after the implementation of the waste management scenarios. For the purposes of this report, a "project" is defined as a single successful development well and the leasing and exploration activities associated with that well. The costs for the model project include the costs of both the unsuccessful and the successful leasing and exploratory and development drilling required, on average, to achieve one successful producing well.

Table VI-5 Assumed Waste Management Practices for Alternative Waste Management Scenarios

Waste management scenario	Drilling wastes: Disposal method	Drilling wastes: Potentially affected operations	Produced waters: Disposal method	Produced waters: Potentially affected operations
Baseline	Unlined surface impoundment Lined surface impoundment	N.A.	Class II injection Surface discharge	N.A.
Intermediate	Baseline practices for nonhazardous wastes For hazardous wastes: - Lined surface impoundment - Landfarming with site management - Solidification - Incineration	Facilities not now using liners: approximately 63% of total[a]	Baseline practices for nonhazardous wastes Class II injection for hazardous wastes	Facilities not now using Class II injection: approximately 20% of total[d]
Subtitle C	Baseline practices for nonhazardous wastes For hazardous wastes: - SCLC impoundment with Subtitle C site management - Landfarming with Subtitle C site management - Hazardous waste incineration	All facilities[b]	Baseline practices for nonhazardous wastes Class I injection for hazardous wastes	All facilities[e]
Subtitle C-1	Same as Subtitle C scenario	Same as Subtitle C scenario[c]	Baseline practices for nonhazardous wastes For hazardous wastes: - Class I injection for nonwaterfloods - Class II injection for waterfloods	Facilities not now waterflooding: approximately 40% of total[f]

[a] In the Intermediate 10% Scenario, 10% of the 63%, or 6.3%, are assumed to be hazardous; in the Intermediate 70% Scenario, 70% of the 63%, or 44.1%, are assumed to be hazardous.

[b] In the Subtitle C 10% Scenario, 10% of the 100%, or 10.0%, are assumed to be hazardous; in the Subtitle C 70% Scenario, 70% of the 100%, or 70.0%, are assumed to be hazardous.

[c] In the Subtitle C-1 10% Scenario, 10% of the 100%, or 10.0%, are assumed to be hazardous; in the Subtitle C-1 70% Scenario, 70% of the 100%, or 70.0%, are assumed to be hazardous.

[d] In the Intermediate 10% Scenario, 10% of the 20%, or 2.0%, are assumed to be hazardous; in the Intermediate 70% Scenario, 70% of the 20%, or 14.0%, are assumed to be hazardous.

[e] In the Subtitle C 10% Scenario, 10% of the 100%, or 10.0%, are assumed to be hazardous; in the Subtitle C 70% Scenario, 70% of the 100%, or 70.0%, are assumed to be hazardous.

[f] In the Subtitle C-1 10% Scenario, 10% of the 40%, or 4.0%, are hazardous and not exempt because of waterflooding. In the Subtitle C-1 70% Scenario, 70% of the 40%, or 28.0%, are hazardous and not exempt because of waterflooding.

For this study, model projects were defined for oil wells (with associated casinghead gas) in the nine active oil and gas zones and for a Lower 48 composite. Model gas projects were defined for the two most active gas-producing zones (the Gulf and Texas/Oklahoma zones). Thus, 12 model projects have been analyzed. The Technical Background Document for the Report to Congress provides a detailed description of the assumptions and data sources underlying the model projects.

A distinct set of economic parameter values is estimated for each of the model projects, providing a complete economic description of each project. The following categories of parameters are specified for each project:

1. Lease Cost: initial payments to Federal or State governments or to private individuals for the rights to explore for and to produce oil and gas.
2. Geological and Geophysical Cost: cost of analytic work prior to drilling.
3. Drilling Cost per Well.
4. Cost of Production Equipment.
5. Discovery Efficiency: the number of wells drilled for one successful well.
6. Production Rates: initial production rates of oil and gas and production decline rates.
7. Operation and Maintenance Costs.
8. Tax Rates: Rates for Federal and State income taxes, severance taxes, royalty payments, depreciation, and depletion.
9. Price: wellhead selling price of oil and gas (also called the "first purchase price" of the product).
10. Cost of Capital: real after-tax rate of return on equity and borrowed investment capital for the industry.
11. Timing: length of time required for each project phase (i.e., leasing, exploration, development, and production).

The actual parameter values for the 12 model projects are summarized in Table VI-6.

For each of the 12 model projects, the economic performance is estimated before (i.e., baseline) and after each waste management scenario has been implemented. Two measures of economic performance are employed in the impact assessment presented here. One is the after-tax rate of return. The other is the cost of production per barrel of oil (here defined as the cost of the resources used in production, including profit to the owners of capital, excluding transfer payments such as royalties and taxes). A number of other economic output parameters are described in the Technical Background Document.

Quantities of Wastes Generated by the Model Projects

To calculate the waste management costs for each representative project, it was necessary to develop estimates of the quantities of drilling and production wastes generated by these facilities. These estimates, based on a recent API survey, are provided in Table VI-7. Drilling wastes are shown on the basis of barrels of waste per well. Production wastes are provided on the basis of barrels of waste per barrel of oil.

For the Lower 48 composite, an estimated 5,170 barrels of waste are generated for each well drilled. For producing wells, approximately 10 barrels of water are generated for every barrel of oil. This latter statistic includes waterflood projects, some of which operate at very high water-to-oil ratios.

Model Project Waste Management Costs

Model project waste management costs are estimated for the baseline and for each waste management scenario using the cost data presented in

Table VI-6 Economic Parameters of Model Projects for U.S. Producing Zones
(All Costs in Thousands of 1985 Dollars, Other Units as Noted)

Parameter	Appalachian	Gulf	Gulf	Midwest	Plains	Texas/ Oklahoma	Texas/ Oklahoma	Northern Mountain	Southern Mountain	West Coast	Alaska	Lower 48 States
Production	Oil/Gas	Oil/Gas	Gas	Oil/Gas	Oil/Gas	Oil/Gas	Gas	Oil/Gas	Oil/Gas	Oil/Gas	Oil/Gas	Oil/Gas
Yr of first prod.	1	1	1	1	1	1	1	2	1	1	10	1
Lease cost	1.146	19.296	154.368	2.509	2.080	11.200	22.400	4.992	2.251	33.178	161.056	14.877
G & G expense	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%	58.3%
Well cost	63.911	244.276	640.146	122.138	186.347	246.324	727.636	421.142	492.053	160.995	3,207.388	248.607
Disc. efficiency	85%	59%	59%	51%	52%	71%	71%	55%q	72%	90%	88%	69%
Infrastructure cost	45.000	73.189	35.297	60.788	81.855	86.820	39.824	102.662	109.357	82.560	45,998.400	83.952
O & M costs (per yr)	4.500	13.349	18.486	11.807	14.529	15.114	21.048	17.015	17.781	13.370	690.900	14.463
Initial prod. rates												
Oil (bbl/day)	4	60	0	16	26	37	0	53	32	35	3700	41
Gas (Mcf/day)	16	82	1295	15	34	69	1038	72	69	0	686	57
Prod. decline rates	9%	19%	19%	17%	19%	12%	12%	13%	13%	7%	9%	12%
Federal corp. tax	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%	34%
State corp. tax	0%	8%	8%	4%	6.75%	5%	5%	0%	6%	9.35%	9.40%	6.14%
Royalty rate	18.75%	18.75%	18.75%	12.50%	12.50%	20.00%	20.00%	12.50%	16.00%	18.75%	14.30%	18.24%
Severance tax												
Oil	0.5%	12.5%	12.5%	0%	8%	7%	7%	6%	4%	0.14%	a	6.67%
Gas	1.5%	4.25%	4.25%	4.84%	0%	8%	7%	7%	6%	4%	0.14%	a
Wellhead price												
Oil ($/bbl)	$20.90	$21.65	$21.65	$22.11	$21.14	$22.03	$22.03	$20.74	$21.16	$18.38	$16.37	$20.00
Gas ($/Mcf)	$ 2.00	$ 1.99	$ 1.99	$ 2.03	$ 1.43	$ 1.58	$ 1.58	$ 1.77	$ 1.98	$ 2.21	$ 0.49	$ 1.65

[a] Tax based on formula in tax code, not a flat percentage.

Source: ERG 1987.

Table VI-7 Average Quantities of Waste Generated, by Zone

Model project/ zone	Drilling waste barrels/well	Produced water (barrels/barrel of oil)
Appalachian	2,344	2.41
Gulf	10,987	8.42
Midwest	1,853	23.61
Plains	3,623	9.11
Texas/Oklahoma	5,555	10.62
Northern Mountain	8,569	12.30
Southern Mountain	7,153	7.31
West Coast	1,414	8.05
Alaska	7,504	0.15
Lower 48 States	5,170	9.98
Gulf (gas only)	10,987	17.17[a]
Texas/Oklahoma (gas only)	5,555	17.17[a]

[a] Barrels of water per million cubic feet of natural gas.

Sources: API 1987a; Flannery and Lannan 1987.

Tables VI-3 and VI-4 and the waste quantity data shown in Table VI-7. For each model project, waste management costs are calculated for each waste management scenario.

For each model project and scenario, the available compliance methods were identified (Table VI-5). Cost estimates for all available compliance methods, including transportation costs for offsite methods, were developed based on the unit cost factors (Tables VI-2 and VI-3) and the waste quantity estimates (Table VI-7). Each model facility was assumed to have selected the lowest cost compliance method. Based on compliance cost comparisons, presented in more detail in the Technical Background Document, the following compliance methods are employed by affected facilities under the waste management scenarios:

<u>Intermediate Scenario</u>

1. Drilling wastes - single-liner onsite facility; volume reduction and transport to offsite single-liner facility if cost-effective.

2. Production wastes - Class II onsite facility.

<u>Subtitle C Scenario</u>

1. Drilling wastes - transport to offsite SCLC facility with site management and with volume reduction if cost-effective.

2. Production wastes - for waterfloods, onsite injection in Class I facility; for nonwaterfloods, transport and disposal in offsite Class I facility.

<u>Subtitle C-1 Scenario</u>

1. Drilling wastes - transport to offsite SCLS facility with site management and with volume reduction if cost-effective.

2. Production wastes - waterfloods exempt; for nonwaterfloods, transport and injection in offsite Class I facility.

For each model facility under each scenario, the least-cost compliance method was assumed to represent the cost of affected projects. Costs for unaffected projects were estimated based on the cost

of baseline practices. Weighted average costs for each model under each scenario (shown in Tables VI-8 and VI-9) incorporate both affected and unaffected projects. For example, in the Subtitle C 70% Scenario, while 70 percent of projects must dispose of drilling wastes in Subtitle C facilities, the other 30 percent can continue to use baseline practices. The weighted average cost is calculated as follows:

Project category	Percentage of projects	Drilling waste disposal cost	Weighted cost
Affected operations	70%	$61,782	$43,248
Unaffected operations	30%	$15,176	$ 4,552
Weighted average			$47,800

For drilling wastes, the weighted average costs range from $15,176 per well in the Baseline to $47,800 per well in the RCRA Subtitle C 70% case. Thus, the economic analysis assumes that each well incurs an additional $32,624 under the RCRA Subtitle C 70% Scenario. For produced water, costs per barrel of water disposed of range from $0.11 in the Baseline to $0.62 in the RCRA Subtitle C 70% Scenario. Thus, there is an additional cost of $0.51 per barrel of water under this scenario.

Impact of Waste Management Costs on Representative Projects

The new oil and gas projects incur additional costs under the alternative waste management scenarios for both drilling and production waste management. By incorporating these costs into the economic model simulations, the impact of these costs on financial performance of typical new oil and gas projects is assessed. These impacts are presented in Tables VI-10 and VI-11.

As shown in Table VI-10, the internal rate of return can be substantially affected by waste management costs, particularly in the Subtitle C 70% Scenario. From a base case level of 28.9 percent, model

Table VI-8 Weighted Average Regional Costs of Drilling Waste Management for Model Projects Under Alternative Waste Management Scenarios (Dollars per Well)

Model project/ zone	Baseline	Intermediate 10%	Intermediate 70%	Subtitle C 10% and Subtitle C-1 10%	Subtitle C 70% and Subtitle C-1 70%
Appalachian	$ 9,465	$ 9,602	$10,420	$12,799	$ 32,801
Gulf	24,582	25,756	32,796	30,848	68,440
Midwest	6,014	6,219	7,447	10,138	34,880
Plains	11,442	11,852	14,312	16,073	43,858
Texas/Oklahoma	17,398	18,258	23,418	21,163	43,755
Northern Mountain	24,186	25,495	33,348	31,965	78,636
Southern Mountain	22,711	23,511	28,594	29,689	71,555
West Coast	2,919	3,258	5,290	6,521	28,135
Alaska	28,779	30,277	39,266	35,333	74,661
Lower 48 States	15,176	15,964	20,964	19,837	47,800

NOTE: Costs in 1985 dollars, based on 1985 cost factors.

Source: ERG estimates.

Table VI-9 Weighted Average Unit Costs of Produced Water Management for Model Projects under Alternative Waste Management Scenarios (Dollars per Barrel of Water)

Model project/ zone	Baseline	Intermediate		Subtitle C		Subtitle C-1	
		10%	70%	10%	70%	10%	70%
Appalachian	$0.52	$0.57	$0.94	$0.80	$2.51	$0.67	$1.57
Gulf	0.08	0.06	0.10	0.16	0.65	0.15	0.57
Midwest	0.14	0.14	0.14	0.22	0.65	0.15	0.20
Plains	0.16	0.16	0.16	0.24	0.74	0.20	0.47
Texas/Oklahoma	0.13	0.13	0.13	0.20	0.61	0.15	0.31
Northern Mountain	0.07	0.07	0.07	0.11	0.36	0.09	0.22
Southern Mountain	0.13	0.13	0.13	0.19	0.55	0.14	0.24
West Coast	0.04	0.04	0.04	0.08	0.34	0.07	0.26
Alaska	0.31	0.31	0.31	0.46	1.42	0.34	0.56
Lower 48 States	0.11	0.11	0.12	0.18	0.62	0.15	0.35

NOTE: Waste management costs applied to both oil and gas production wastes. Costs in 1985 dollars.

Source: ERG estimates.

Table VI-10 Impact of Waste Management Costs on Model Projects: Comparisons of After-Tax Internal Rate of Return [a]

(%)

Model project/ zone	Baseline	Alternative waste management scenarios					
		Intermediate		Subtitle C		Subtitle C-1	
		10%	70%	10%	70%	10%	70%
Appalachian	10.3%	10.2%	8.9%	8.9%	0.9%	9.2%	3.6%
Gulf-gas	22.9	22.8	22.5	22.5	20.7	22.6	20.7
Gulf-oil	36.4	36.2	34.5	33.2	15.6	33.5	17.9
Midwest	12.1	12.1	11.8	8.2	-19.4	10.9	5.1
Plains	9.0	9.0	8.6	6.9	-5.6	7.7	0.0
Texas/Oklahoma-gas	19.6	19.5	19.3	19.4	18.3	19.4	18.5
Texas/Oklahoma-oil	29.6	29.5	28.9.	27.4	14.6	28.4	22.1
Northern Mountain	19.6	19.5	19.0	18.2	10.1	18.6	13.1
Southern Mountain	9.2	9.2	9.0	8.3	3.3	8.7	6.3
West Coast	35.0	35.0	34.5	33.6	25.4	33.8	26.9
Alaska	10.9	10.9	10.9	10.8	10.6	10.9	10.8
Lower 48 States	28.9	28.8	28.0	26.6	13.0	27.6	19.7

NOTE: Both drilling and production wastes regulated.

[a] Internal rate of return defined as return after corporate taxes, to total invested capital including both equity and debt.

Source: ERG estimates.

Table VI-11 Impact of Waste Management Costs on Model Projects: Increase in Total Cost of Production[a] (Dollars per Barrel of Oil Produced)

Model project/ zone	Total baseline cost	Increase in cost under alternative waste management scenarios					
		Intermediate		Subtitle C		Subtitle C-1	
		10%	70%	10%	70%	10%	70%
Appalachian	$16.22	$ 0.05	$ 0.44	$ 0.45	$ 3.24	$ 0.33	$ 2.35
Gulf-gas	9.45	0.01	0.03	0.03	0.20	0.03	0.20
Gulf-oil	15.65	0.01	0.17	0.40	2.85	0.36	2.48
Midwest	19.45	0.01	0.07	1.11	8.31	0.34	2.12
Plains	18.46	0.02	0.09	0.51	3.69	0.33	2.46
Texas/Oklahoma-gas	7.61	0.01	0.02	0.02	0.11	0.02	0.09
Texas/Oklahoma-oil	14.86	0.01	0.07	0.40	1.24	0.20	2.74
Northern Mountain	15.51	0.02	0.12	0.36	2.56	0.23	1.65
Southern Mountain	18.05	0.01	0.08	0.29	2.01	0.16	0.99
West Coast	13.19	0.00	0.07	0.23	1.68	0.18	1.34
Alaska	15.02	0.00	0.00	0.01	0.10	0.00	0.03
Lower 48 States	14.11	0.01	0.11	0.40	2.88	0.20	1.55

[a] Total cost of production defined to include capital costs, operating costs, lease bonus costs, and pollution control costs, as well as transfer payments such as Federal income taxes, royalties, and State severance taxes.

Source: ERG estimates.

project after-tax internal rates of return decline under the waste management scenarios to the 13.0 to 28.8 percent range for the Lower 48 average.

The after-tax cost of producing hydrocarbons can also increase substantially. As Table VI-11 shows, these costs can increase by up to $2.98 per barrel of oil equivalent (BOE), a 20 percent increase over baseline costs. The impacts of these cost increases on a national level are described further below.

REGIONAL- AND NATIONAL-LEVEL COMPLIANCE COSTS OF THE WASTE MANAGEMENT SCENARIOS

The cost of waste management for the typical projects under each waste management scenario (see Tables VI-8 and VI-9) were used in conjunction with annual drilling (API 1986) and production levels (API 1987c) to estimate the regional- and national-level annual costs of the waste management scenarios. These costs, which include both drilling and production waste disposal costs, are presented in Table VI-12. National-level costs range from $49 million in the Intermediate 10% Scenario to more than $12.1 billion in the Subtitle C 70% Scenario.

The costs presented in Table VI-12 do not include the effects of closures. They are based on 1985 drilling and production levels, assuming that no activities are curtailed because of the requirements of the waste management scenarios. In reality, each of the waste management scenarios would result in both the early closure of existing projects and the cancellation of new projects. To the extent that the level of oil and gas activity declines, total aggregate compliance costs incurred under each waste management scenario will be lower, but there will be other costs to the national economy caused by lower levels of oil production. These effects are described more fully below.

Table VI-12 Annual Regional and National RCRA Compliance Cost of Alternative Waste Management Scenarios (Millions of Dollars)

Model project/ zone	Waste management scenarios					
	Intermediate		Subtitle C		Subtitle C-1	
	10%	70%	10%	70%	10%	70%
Appalachian	$5	$43	$57	$403	$47	$328
Gulf	8	94	200	1,417	180	1,239
Midwest	1	6	120	870	31	185
Plains	2	17	126	907	77	576
Texas/Oklahoma	26	181	879	6,156	442	2,873
Northern Mountains	3	19	94	677	55	404
Southern Mountains	3	21	92	643	47	297
West Coast	1	36	126	936	97	736
Alaska	0	2	17	118	5	34
Lower 48 States	49	418	1,693	12,007	975	6,637
National Total	49	420	1,710	12,125	980	6,671

NOTE: Figures represent before-tax total annual increase in waste management cost over baseline costs at 1985 levels of drilling and production, without adjusting for decreases in industry activity caused by higher production costs at affected sites. Column totals may differ because of independent rounding. Base year for all costs is 1985.

CLOSURE ANALYSIS FOR EXISTING WELLS

The potential of the waste management scenarios to shut down existing producing wells was estimated using the model facility approach. The model facility simulations for existing projects, however, do not include the initial capital cost of leasing and drilling the production well. For the analysis of existing projects, it is assumed that these costs have already been incurred. The projects are simulated for their operating years. If operating revenues exceed operating costs, the projects remain in production.

Closures of existing wells are estimated by using a variable called the economic limit (i.e., a level of production below which the project cannot continue to operate profitably). Under the waste management scenarios, produced water disposal costs are higher and, therefore, the economic limit is higher. Some projects that have production levels that exceed the baseline economic limit would fall below the economic limit under the alternative waste management scenarios. Those projects not meeting this higher level of production can be predicted to close. This analysis was conducted only with respect to stripper wells. To the extent that certain high-volume, low-margin wells may also be affected, the analysis may understate short-term project closures.

The economic limit analysis requires information on the distribution of current production levels across wells. Because of the lack of data for most States, the economic limit analysis is presented here only for Texas and on a national level. The 1985 distribution of production by volume size class for Texas and for the Nation as a whole is shown in Table VI-13.

Table VI-14 displays the results of the economic limit analysis. Under baseline assumptions, the representative Lower 48 project requires 2.40 barrels per day to remain in operation. The economic limit for

Table VI-13 Distribution of Oil Production Across Existing Projects, 1985

Region	Production Interval (BOPD) bbl/d	Number of Wells	Total Oil Production 1000 bb/d
National			
	0 - 1	112,000	71
	1 - 2	112,000	165
	2 - 3	78,000	206
	3 - 4	65,000	231
	4 - 5	20,000	92
	5 - 6	27,000	154
	6 - 7	21,000	142
	7 - 8	16,000	119
	8 - 9	15,000	129
	9 - 10	9,000	63
Total		475,000	1,371
Texas	<1	42,881	21
	1.0 - 1.5	15,018	19
	1.6 - 2.5	20,856	43
	2.6 - 3.5	14,018	43
	3.6 - 4.5	11,303	46
	4.6 - 5.5	9,665	49
	5.6 - 6.5	7,638	46
	6.6 - 7.5	6,201	44
	7.6 - 8.6	5,420	44
	9.6 - 1.05	4,441	45
Total			142,743
446			

Sources: :The Effect of Lower Oil Prices on Production From Proved U.S. Oil Reserves," Energy and Environmental Analysis, Inc., February 1987, taken from Figure 2-2. Indicators: A Monthlv Data Review-April 1986, Railroad Commission of Teas, April 1986.

Table VI-14 Impact of Waste Management Cost on Existing Production

Region	Scenario	Economic limit (bbl/d)	Lower-range effects: Well closures: Number of wells	Lower-range effects: Well closures: Percent of wells	Lower-range effects: Lost production: 1000 bbl/d	Lower-range effects: Lost production: Percent of production	Upper-range effects: Well closures: Number of wells	Upper-range effects: Well closures: Percent of wells	Upper-range effects: Lost production: 1000s bbl/d	Upper-range effects: Lost production: Percent of production
Texas										
	Baseline[a]	2.30								
	Intermediate 10%	2.32	42	0.02	0.09	0.00	6,562	3.29	5.60	0.24
	Intermediate 70%	2.32	292	0.15	0.60	0.03	45,931	23.05	33.22	1.67
	Subtitle C 10%	3.89	2,260	1.13	6.92	0.30	8,780	4.41	12.00	0.53
	Subtitle C 70%	3.89	15,818	7.94	48.41	2.07	61,457	30.84	87.04	3.71
	Subtitle C-1 10%	2.73	740	0.37	1.84	0.08	7,259	3.64	7.36	0.31
	Subtitle C-1 70%	2.73	5,177	2.60	12.87	0.55	50,816	25.50	51.49	2.20
National:	Lower 48 States									
	Baseline[b]	2.40								
	Intermediate 10%	2.42	156	0.03	0.41	0.00	20,652	3.33	21.00	0.25
	Intermediate 70%	2.42	1,092	0.18	2.88	0.03	144,564	23.31	148.45	1.75
	Subtitle C 10%	4.20	11,580	1.87	37.32	0.44	32,076	5.17	58.00	0.68
	Subtitle C 70%	4.20	81,060	13.07	261.23	3.07	224,532	36.20	406.79	4.79
	Subtitle C-1 10%	3.01	4,745	0.77	13.00	0.15	25,241	4.07	33.00	0.39
	Subtitle C-1 70%	3.01	33,215	5.36	88.14	1.04	176,687	28.49	233.70	2.75

[a] Baseline production level is 2.3 million bbl/d; baseline well total is 199,000.
[b] Baseline production level is 8.6 million bbl/d; baseline well total is 620,000.

Source: ERG estimates.

affected operations rises to 3.01 to 4.20 barrels per day under the waste management scenarios. The increase in the economic limit results in closures of from 0.03 percent to 36.20 percent of all producing wells.

The "lower-range effects" in Table VI-14 assume that only affected wells (i.e., wells generating hazardous produced waters) producing at levels <u>between</u> the baseline economic limit and the economic limit under the waste management scenarios will be closed. The "upper-range effects" assume that all affected wells producing at levels below the economic limit under the waste management scenarios will be closed, and are adjusted to account for the change in oil prices from 1985 to 1986.

Under the lower-range effects case, production losses are estimated at between 0.00 and 3.07 percent of total production. Under the upper-range effects assumptions, production closures range from 0.25 to 4.79 percent of the total. These results are indicative of the immediate, short-term impact of the waste management scenarios caused by well closures.

The results of the Texas simulation mirror those of the national-level analysis. This would be expected, since nearly 30 percent of all stripper wells are in Texas, and the State is, therefore, reflected disproportionately in the national-level analysis. Under the lower-range effects assumptions, Texas production declines between 0.00 and 2.07 percent. Under the upper-range effects assumptions, Texas production declines between 0.24 and 3.71 percent.

THE INTERMEDIATE AND LONG-TERM EFFECTS OF THE WASTE MANAGEMENT SCENARIOS

Production Effects of Compliance Costs

The intermediate and long-term effects of the waste management scenarios will exceed the short-term effects for two principal reasons.

First, the increases in drilling waste management cost, which do not affect existing producers, can influence new project decisions. Second, the higher operating costs due to produced water disposal requirements may result in some project cancellations because of the expectation of reduced profitability during operating years. Although such projects might be expected to generate profits in their operating years (and therefore might be expected to operate if drilled), the reduced operating profits would not justify the initial investment.

The intermediate and long-term production effects were estimated using Department of Energy (DOE) production forecasting models. As described above, an economic simulation model was used to calculate the increase in the cost of resource extraction under each waste management scenario. These costs were used in conjunction with the DOE FOSSIL2 model (DOE 1985) and the DOE PROLOG model (DOE 1982) to generate estimates of intermediate and long-term production effects of the waste management scenarios.

For the FOSSIL2 model, an estimate of the increase in resource extraction costs for each waste management scenario, based on model project analysis, was provided as an input. Simulations were performed to measure the impact of this cost increase on the baseline level of production.

For the PROLOG model, no new simulations were performed. Instead, results of previous PROLOG modeling were used to calculate the elasticity of supply with respect to price in the PROLOG model. The model project simulation results were used to calculate an oil price decline that would have the same impact as the cost increase occurring under each alternative waste management scenario. These price increases were used in conjunction with an estimate of the price elasticity of supply from the PROLOG model to estimate an expected decline in production for each waste management scenario.

Table VI-15 shows the results of this analysis. The long-term impacts of the waste management scenarios range from levels that are below the detection limits of the modeling system to declines in production ranging up to 32 percent in the year 2000, based on the PROLOG analysis. For the FOSSIL2 simulations, production declines were estimated to range from "not detectable" to 18 percent in the year 2000 and from "not detectable" to 29 percent in the year 2010.

Additional Impacts of Compliance Costs

The decline in U.S. oil production brought about by the cost of the waste management scenarios would have wide-ranging effects on the U.S. economy. Domestic production declines would lead to increased oil imports, a deterioration in the U.S. balance of trade, a strengthening of OPEC's position in world markets, and an increase in world oil prices. Federal and State revenues from leasing and from production and income taxes would decline. Jobs would be lost in the oil and gas drilling, servicing, and other supporting industries; jobs would be created in the waste management industries (e.g., contractors who drill and complete Class I injection wells).

It is beyond the scope of this report to fully analyze all of these and other macroeconomic effects. To illustrate the magnitude of some of these effects, however, five categories of impacts were defined and quantified (oil imports, balance of trade, oil price, Federal leasing revenues, and State production taxes). These are presented in Table VI-16. Measurable effects are evident for all but the lowest cost (Intermediate 10% Scenario).

The impacts of the waste management scenarios on the U.S. economy were analyzed utilizing the DOE FOSSIL2/WOIL modeling system. Cost increases for U.S. oil producers create a slight decrease in the world oil supply curve (i.e., the amount of oil that would be brought to market at any oil price declines). The model simulates the impact of this shift on the world petroleum supply, demand, and price.

Table VI-15 Long-Term Impacts on Production of Cost Increases under Waste Management Scenarios

(%) Scenario	Estimated resource extraction cost increase (%)	Decline of domestic oil production in lower 48 States				
		Year 1990		Year 2000		Year 2010
		FOSSIL2	PROLOG	FOSSIL2	PROLOG	FOSSIL2
Intermediate 10%	0.16	No detectable change	No detectable change	No detectable change	No detectable change	No detectable change
Intermediate 70%	2.49	No detectable change	No detectable change	1.4%	No detectable change to 0.4%	1.6%
Subtitle C 10%	9.51	No detectable change	0.3% to 0.4%	4.2%	1.6% to 3.5%	6.3%
Subtitle C 70%	68.84	3.2%	6.9% to 7.8%	18.1%	19.1% to 32.4%	28.6%
Subtitle C-1 10%	4.73	No detectable change	No detectable change	1.4%	0.3% to 1.4%	3.2%
Subtitle C-1 70%	36.51	2.1%	3.7% to 4.3%	12.5%	10.7% to 18.5%	19.0%

Source: ERG estimates for extraction cost increase and for PROLOG impacts. Applied Energy Services of Arlington, Virginia, (Wood 1987) for FOSSIL2 results, based on specific runs of U.S. Department of Energy FOSSIL2 Model for alternative scenario cost increases. Department of Energy baseline crude oil price per barrel assumptions in FOSSIL2 were $20.24 in 1990, $33.44 in 2000, and $52.85 in 2010.

Table VI-16 Effect of Domestic Production Decline on Selected Economic Parameters in the Year 2000

Waste management scenario	Projected decline in lower 48 production (%)[a]	Increase in petroleum imports (millions of barrels per day)	Increase in U.S. balance of trade deficit ($ billions per year)	Increase in world oil price (dollars per barrel)[a]	Annual cost to consumers of the oil price increase ($ billions per year)	Decrease in Federal leasing revenues ($ millions per year)	Decrease in State tax revenues ($ millions per year)
Intermediate 10%	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.	N.D.
Intermediate 70%	1.4%	N.D.	$0.2	$0.06	$0.4	$19.1	$71.0
Subtitle C 10%	4.2%	0.2	$3.2	$0.21	$1.2	$53.6	$208.9
Subtitle C 70%	18.1%	1.1	$17.5	$1.08	$6.4	$279.8	$903.2
Subtitle C-1 10%	1.4%	0.1	$1.6	$0.12	$0.7	$20.9	$60.7
Subtitle C-1 70%	12.5%	0.7	$11.3	$0.76	$4.5	$176.2	$616.1

N.D. - Not detectable using the FOSSIL2/WOIL modeling system.

[a] Revised baseline values for year 2000 in the FOSSIL2 modeling system include (1) lower 48 States crude oil production of 7.2 million barrels per day; (2) U.S. imports of 9.2 million barrels per day; and (3) world crude oil price of $33.44 per barrel.

Source: Results based on U.S. Department of Energy's FOSSIL2/WOIL energy modeling system, with special model runs for individual waste management scenario production costs effects conducted by Applied Energy Services of Arlington, Virginia (Wood 1987). ERG estimates based on FOSSIL2 results.

A new equilibrium shows the following effects:

- A lower level of domestic supply (previously depicted in Table VI-15);
- A higher world oil price (see Table VI-16);
- A decrease in U.S. oil consumption caused by the higher world oil price; and
- An increase in U.S. imports to partially substitute for the decline in domestic supply (also shown in Table VI-16).

The first numerical column in Table VI-16 shows the decline in U.S. production associated with each waste management scenario. These projections, derived from simulations of the FOSSIL2/WOIL modeling system, were previously shown in Table VI-15. The second column in Table VI-16 provides FOSSIL2/WOIL projections of the increase in petroleum imports necessary to replace the lost domestic supplies. The projections range from "not detectable" to 1.1 million barrels per day, equal to 1.4 to 18.1 percent of current imports of approximately 6.1 million barrels per day.

The third column in Table VI-16 shows the increase in the U.S. balance of trade deficit resulting from the increase in imports and the increase in the world oil price. The increase in the U.S. balance of trade deficit ranges from $0.2 to $17.5 billion under the waste management scenarios. The projected increase in petroleum imports under the most restrictive regulatory scenarios could be a matter for some concern in terms of U.S. energy security perspectives, making the country somewhat more vulnerable to import disruptions and/or world oil price fluctuations. In the maximum case estimated (Subtitle C 70% Scenario), import dependence would increase from 56 percent of U.S. crude oil requirements in the base case to 64 percent in the year 2000.

The fourth column shows the crude petroleum price increase projected under each of the waste management scenarios by the FOSSIL2/WOIL modeling system. This increase ranges from $0.06 to $1.08 per barrel of oil (a 0.2 to 3 percent increase). This increase in oil price translates into an increase in costs to the consumer of $0.4 to $6.4 billion in the year 2000 (column five). These estimates are derived by multiplying FOSSIL2-projected U.S. crude oil consumption in the year 2000 by the projected price increase. The estimates assume that the price increase is fully passed through to the consumer with no additional downstream markups.

Federal leasing revenues will also decline under the waste management scenarios. These revenues consist of lease bonus payments (i.e., initial payments for the right to explore Federal lands) and royalties (i.e., payments to the Federal government based on the value of production on Federal lands). Both of these revenue sources will decline because of the production declines associated with the waste management scenarios. If the revenue sources are combined, there will be a reduction of $19 to $280 million in Federal revenues in the year 2000.

State governments generally charge a tax on crude oil production in the form of severance taxes, set as a percentage of the selling price. On a national basis, the tax rate currently averages approximately 6.7 percent. Applying this tax rate, the seventh column in Table VI-16 shows the projected decline in State tax revenues resulting from the waste management scenarios. These estimates range from about $60 million to $900 million per year.

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CHAPTER VII

CURRENT REGULATORY PROGRAMS

INTRODUCTION

A variety of programs exist at the State and Federal levels to control the environmental impacts of waste management related to the oil and gas industry. This chapter provides a brief overview of the requirements of these programs. It also presents summary statistics on the implementation of these programs, contrasting the numbers of wells and other operations regulated by these programs with resources available to implement regulatory requirements.

State programs have been in effect for many years, and many have evolved significantly over the last decade. The material presented here provides only a general introduction to these complex programs and does not attempt to cover the details of State statutes and current State implementation policy. Additional material on State regulatory programs can be found in Appendix A. Federal programs are administered both by the Environmental Protection Agency and by the Bureau of Land Management within the U.S. Department of the Interior.

STATE PROGRAMS

The tables on the following pages compare the principal functional requirements of the regulatory control programs in the principal oil- and gas-producing States that have been the focus of most of the analysis of this study. These States are Alaska, Arkansas, California, Colorado, Kansas, Louisiana, Michigan, New Mexico, Ohio, Oklahoma, Texas, West Virginia, and Wyoming.

Table VII-1 covers requirements for reserve pit design, construction, and operation; Table VII-2 covers reserve pit closure and waste removal. Table VII-3 presents requirements for produced water pit design and construction, while Table VII-4 compares requirements for the produced water surface discharge limits. Table VII-5 deals with produced water injection well construction; these requirements fall under the general Federal Underground Injection Control program, which is discussed separately below under Federal programs. Finally, Table VII-6 discusses requirements for well abandonment and plugging.

FEDERAL PROGRAMS--EPA

Federal programs discussed in this section include the Underground Injection Control (UIC) program and the Effluent Limitations Guidelines program administered by the EPA.

Underground Injection Control

The Underground Injection Control (UIC) program was established under Part C of the Safe Drinking Water Act (SDWA) to protect underground sources of drinking water (USDWs) from endangerment by subsurface emplacement of fluids through wells. Part C of the SDWA requires EPA to:

1. Identify the States for which UIC programs may be necessary--EPA listed all States and jurisdictions;
2. Promulgate regulations establishing minimum requirements for State programs which:
   - prohibit underground injection that has not been authorized by permit or by rule;
   - require applicants for permits to demonstrate that underground injection will not endanger USDWs;
   - include inspection, monitoring, record-keeping, and reporting requirements.

These minimum requirements are contained in 40 CFR Parts 144 and 146, and were promulgated in June 1980.

3. Prescribe by regulation a program applicable to the States, in cases where States cannot or will not assume primary enforcement responsibility. These direct implementation (DI) programs were codified in 40 CFR Part 147.

The regulations promulgated in 1980 set minimum requirements for 5 classes of wells including Class II wells--wells associated with oil and gas production and hydrocarbon storage. In December 1980, Congress amended the SDWA to allow States to demonstrate the effectiveness of their in-place regulatory programs for Class II wells, in lieu of demonstrating that they met the minimum requirements specified in the UIC regulations. In order to be deemed effective, State Class II programs had to meet the same statutory requirements as the other classes of wells, including prohibition of unauthorized injection and protection of underground sources of drinking water. (§1425 SDWA). Because of the large number of Class II wells, the regulations allow for authorization by rule for existing enhanced recovery wells (i.e., wells that were injecting at the time a State program was approved or prescribed by EPA). In DI States, these wells are subject to requirements specified in Part 147 for authorization by rule, which are very similar to requirements applicable to permitted wells, with some relief available from casing and cementing requirements as long as the wells do not endanger USDWs. In reviewing State programs where the intent was to "grandfather" existing wells as long as they met existing requirements, EPA satisfied itself that these requirements were sufficient to protect USDWs. In addition, all States adopted the minimum requirements of §146.08 for demonstrating mechanical integrity of the wells (ensuring that the well was not leaking or allowing fluid movement in the borehole), at least every 5 years. This requirement was deemed by EPA

to be absolutely necessary in order to prevent endangerment of USDWs. In addition, EPA and the States have been conducting file reviews of all wells whether grandfathered or subject to new authorization-by-rule requirements. File reviews are assessments of the technical issues that would normally be part of a permit decision, including mechanical integrity testing, construction, casing and cementing, operational history, and monitoring records. The intent of the file review is to ensure that injection wells not subject to permitting are technically adequate and will not endanger underground sources of drinking water.

Because of §1425 and the mandate applicable to Federal programs not to interfere with or impede underground injection related to oil and gas production, to avoid unnecessary disruption of State programs and to consider varying geologic, hydrologic, and historical conditions in different States, EPA has accepted more variability in this program than in many of its other regulatory programs. Now that the program has been in place for several years, the Agency is starting to look at the adequacy of the current requirements and may eventually require more specificity and less variation among States.

Effluent Limitations Guidelines

On October 30, 1976, the Interim Final BPT Effluent Limitations Guidelines for the Onshore Segment of the Oil and Gas Extraction Point Source Category were promulgated as 41 FR (44942). The rulemaking also proposed Best Available Technology Economically Achievable (BAT) and New Source Performance Standards.

On April 13, 1979, BPT Effluent Limitations Guidelines were promulgated for the Onshore Subcategory, Coastal Subcategory, and Agricultural and Wildlife Water Use Subcategory of the Oil and Gas Extraction Industry (44 FR 22069). Effluent limitations were reserved for the Stripper Subcategory because of insufficient technical data.

The 1979 BPT regulation established a zero discharge limitation for all wastes under the Onshore Subcategory. Zero discharge Agricultural and Wildlife Subcategory limitations were established, except for produced water, which has a 35-mg/L oil and grease limitation.

The American Petroleum Institute (API) challenged the 1979 regulation (including the BPT regulations for the Offshore Subcategory) (661 F.2D.340(1981)). The court remanded EPA's decision transferring 1,700 wells from the Coastal to the Onshore Subcategory (47 FR 31554). The court also directed EPA to consider special discharge limits for gas wells.

Summary of Major Regulatory Activity Related to Onshore Oil and Gas

October 13, 1976	- Interim Final BPT Effluent Limitations Guidelines and Proposed (and Reserved) BAT Effluent Limitations Guidelines and New Source Performance Standards for the Onshore Segment of the Oil and Gas Extraction Point Source Category
April 13, 1979	- Final Rules
	- BPT Final Rules for the Onshore, Coastal, and Wildlife and Agricultural Water Use Subcategories - Stripper Oil Subcategory reserved - BAT and NSPS never promulgated

July 21, 1982 - Response to American Petroleum Institute vs. EPA Court Decision

- Recategorization of 1,700 "onshore" wells to Coastal Subcategory
- Suspension of regulations for Santa Maria Basin, California
- Planned reexamination of marginal gas wells for separate regulations

Onshore Segment Subcategories

Onshore

- BPT Limitation

  -- Zero discharge

- Defined: NO discharge of wastewater pollutants into navigable waters from ANY source associated with production, field exploration, drilling, well completion, or well treatment (i.e., produced water, drilling muds, drill cuttings, and produced sand).

Stripper (Oil Wells)[1]

- Category reserved

- Defined: TEN barrels per well per calendar day or less of crude oil.

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[1] This subcategory does not include marginal gas wells.

Coastal

- BPT Limitations

  -- No discharge of free oil (no sheen)

  -- Oil and grease: 72 mg/L (daily)
  48 mg/L (average monthly)
  (produced waters)

- Defined: Any body of water landward of the territorial seas or any wetlands adjacent to such waters.

Wildlife and Agriculture Use

- BPT Limitations

  -- Oil and Grease: 35 mg/L (produced waters)
  -- Zero Discharge: ANY waste pollutants

- Defined: That produced water is of good enough quality to be used for wildlife or livestock watering or other agricultural uses west of the 98th meridian.

FEDERAL PROGRAMS--BUREAU OF LAND MANAGEMENT

Federal programs under the Bureau of Land Management (BLM) within the U.S. Department of the Interior are discussed in this section.

Introduction

Exploration, development, drilling, and production of onshore oil and gas on Federal and Indian lands are regulated separately from non-Federal lands. This separation of authority is significant for western States where oil and gas activity on Federal and Indian lands is a large proportion of statewide activity.

Regulatory Agencies

The U.S. Department of the Interior exercises authority under 43 CFR 3160 for regulation of onshore oil and gas practices on Federal and Indian lands. The Department of the Interior administers its regulatory program through BLM offices in the producing States. These offices generally have procedures in place for coordination with State agencies on regulatory requirements. Where written agreements are not in place, BLM usually works cooperatively with the respective State agencies. Generally, where State requirements are more stringent than those of BLM, operators must comply with the State requirements. Where State requirements are less stringent, operators must meet the BLM requirements.

The Bureau works closely with the U.S. Forest Service for surface stipulations in Federal forests or Federal grasslands. This cooperative arrangement is specifically provided for in the Federal regulations.

Rules and Regulations

BLM has authority over oil and gas activities on Federal lands. The authority includes leasing, bonding, royalty arrangements, construction and well spacing regulations, waste handling, most waste disposal, site reclamation, and site maintenance.

Historically, BLM has controlled oil and gas activities through Notices to Lessees (NTLs) and through the issuance of permits. The Bureau is working to revise all notices into Oil and Gas Orders, which will be Federally promulgated. To date, Oil and Gas Order No. 1 has been issued.

While the regulations, NTLs, and orders provide the general basis for regulation of oil and gas activities on Federal and Indian lands, there are variations in actual application of some of the requirements among BLM districts. In many cases, the variations are in response to specific geographical or geological characteristics of particular areas.

For example, in middle and southern Florida, the water table is near the surface. As a result, BLM requires the use of tanks instead of mud pits for oil and gas drilling activities on Federal lands in this area. In southeast New Mexico, there is simultaneous development of potash resources and oil and gas resources, and drilling and development requirements are imposed to accommodate the joint development activities. In general, more stringent controls of wastes and of disposal activities are required for oil and gas activities that could affect ground-water aquifers used for drinking water.

Drilling

Before beginning to drill on Federal land, operators must receive a permit to drill from BLM. The permit application must include a narrative description of waste handling and waste disposal methods planned for the well. Any plans to line the reserve pit must be detailed.

The lease is required to be covered by a bond prior to beginning drilling of the well. But the bonds may be for multiple wells, on a lease basis, statewide basis, or nationwide basis. The current bond requirement for wells on a single lease is $10,000. Statewide bonds are $25,000, but bonds must be provided separately for wells on public land and wells on Federally acquired land. The requirement for a nationwide bond is $150,000.

BLM considers reserve pits, and some other types of pits, as temporary. Except in special circumstances, reserve pits do not have to be lined. NTL-2B contains the following provisions for "Temporary Use of Surface Pits":

> Unlined surface pits may be used for handling or storage of fluids used in drilling, redrilling, reworking, deepening, or plugging of a well provided that such facilities are promptly and properly emptied and restored upon completion of the operations. Mud or other fluids contained in such pits shall not be disposed of by cutting the pit walls without the prior authorization of the authorized officer.
>
> Unlined pits may be retained as emergency pits, if approved by the authorized officer, when a well goes into production.
>
> Landspreading of drilling and reworking wastes by breaching pit walls is allowed when approved by the authorized officer.

Production

Produced waters may be disposed of by underground injection, by disposal into lined pits, or "by other acceptable methods." An application to dispose of produced water must specify the proposed method and provide information that will justify the method selected. One application may be submitted for the use of one disposal method for produced water from wells and leases located in a single field, where the water is produced from the same formation or is of similar quality.

Disposal in Pits: A number of general requirements apply to disposal into permanent surface disposal pits, whether lined or unlined. The pits must:

1. Have adequate storage capacity to safely contain all produced water even in those months when evaporation rates are at a minimum;
2. Be constructed, maintained, and operated to prevent unauthorized surface discharges of water; unless surface discharge is authorized, no siphon, except between pits, will be permitted;
3. Be fenced to prevent livestock or wildlife entry to the pit, when required by an authorized officer;
4. Be kept reasonably free from surface accumulations of liquid hydrocarbons by use of approved skimmer pits, settling tanks, or other suitable equipment; and
5. Be located away from the established drainage patterns in the area and be constructed so as to prevent the entrance of surface water.

Approval of disposal of produced water into unlined pits will be considered only if one or more of the following applies:

- The water is of equal or better quality than potentially affected ground water or surface waters, or contains less than 5,000 ppm total dissolved solids (annual average) and no objectionable levels of other toxic constituents;

- A substantial proportion of the produced water is being used for beneficial purposes, such as irrigation or livestock or wildlife watering;
- The volume of water disposed of does not exceed a monthly average of 5 barrels/day/facility; and
- A National Pollutant Discharge Elimination System (NPDES) permit has been granted for the specific disposal method.

Operators using unlined pits are required to provide information regarding the sources and quantities of produced water, topographic map, evaporation rates, estimated soil percolation rates, and "depth and extent of all usable water aquifers in the area."

Unlined pits may be used for temporary containment of fluids in emergency circumstances as well as for disposal of produced water. The pit must be emptied and the fluids appropriately disposed of within 48 hours after the emergency.

Where disposal in lined pits is allowed, the linings of the pits must be impervious and must not deteriorate in the presence of hydrocarbons, acids, or alkalis. Leak detection is required for all lined produced water disposal pits. The recommended detection system is an "underlying gravel-filled sump and lateral system." Other systems and methods may be considered acceptable upon application and evaluation. The authorized officer must be given the opportunity to examine the leak detection system before installation of the pit liner.

When applying for approval of surface disposal into a lined pit, the operator must provide information including the lining material and leak detection method for the pit, the pit's size and location, its net evaporation rate, the method for disposal of precipitated solids, and an analysis of the produced water. The water analysis must include concentrations of chlorides, sulfates, and other (unspecified) constituents that could be toxic to animal, plant, or aquatic life.

Injection: Produced waters may be disposed of into the subsurface, either for enhanced recovery of hydrocarbon resources or for disposal. Since the establishment of EPA's underground injection control program for Class II injection wells, BLM no longer directly regulates the use of injection wells on Federal or Indian lands. Instead, it defers to either EPA or the State, where the State has received primacy for its program, for all issues related to ground-water or drinking water protection. Operators must obtain their underground injection permits from either EPA or the State.

BLM still retains responsibility for making determinations on injection wells with respect to lease status, protection of potential oil and gas production zones, and the adequacy of pressure-control and other safety systems. It also requires monthly reports on volumes of water injected.

Plugging/Abandonment

When a well is a dry hole, plugging must take place before removal of the drilling equipment. The mud pits may be allowed to dry before abandonment of the site. No abandonment procedures may be started without the approval of an authorized BLM representative. Final approval of abandonment requires the satisfactory completion of all surface reclamation work called for in the approved drilling permit.

Within 90 days after a producing well ceases production, the operator may request approval to temporarily abandon the well. Thereafter, reapproval for continuing status as temporarily abandoned may be required every 1 or 2 years. Exact requirements depend on the District Office and on such factors as whether there are other producing wells on the lease. The well may simply be defined as shut-in if equipment is left in place.

Plugging requirements for wells are determined by the BLM District Office. Typically, these will include such requirements as a 100-foot cement plug over the shoe of the surface casing (half above, half below), a 20- to 50-foot plug at the top of the hole, and plugs (usually 100 feet across) above and below all hydrocarbon or freshwater zones.

IMPLEMENTATION OF STATE AND FEDERAL PROGRAMS

Table VII-7 presents preliminary summary statistics on the resources of State oil and gas regulatory programs for the 13 States for which State regulatory programs have been summarized in Tables VII-1 through VII-6. Topics covered include rates of gas and oil production, the number of gas and oil wells, the number of injection wells, the number of new wells, the responsible State agency involved, and the number of total field staff in enforcement positions.

Table VII-8 presents similar statistics covering activities of the Bureau of Land Management. Since offices in one State often have responsibilities for other States, each office is listed separately along with the related States with which it is involved. Statistics presented include the number of oil and gas producing leases, the number of nonproducing oil and gas leases, and the number of enforcement personnel available to oversee producing leases.

Table VII- 1 Reserve Pit Design, Construction and Operation

State	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/ oversight
Alaska	The pits must be rendered impervious.	Whether reserve pit requires lining (and what kind of lining) depends on proximity to surface water and populations, whether the pit is above permafrost, and what kind of pit management strategy is used; visual monitoring required, and ground water monitoring usually required.	Fluid mgmt provision entails use of dewatering practices to keep to a minimum the hydrostatic head in a containment structure to reduce the potential for seepage and to prevent overflow during spring thaw.	Reserve pit "drilling wastes" defined as including "drilling muds, cuttings, hydrocarbons, brine, acid, sand, and emulsions or mixtures of fluids produced from and unique to the operation or maintenance of a well."	Individual permit for active and new pits.
Arkansas (revisions due in '88)	Oil & Gas Commission (OGC); no specific regulations governing construction or management of reserve pits. Dept. of Pollution Control & Ecology (DPCE) incorporates specific requirements in letters of authorizataion serving as informal permits, but regulatory basis and legal enforceability not supported by OGC.	OGC: No regulatory requirement. DPCE: 20-mil synthetic or 18-24 inch thick liner (per authorization letter).	1-ft freeboard (DPCE: 2-ft per authorization letter).	DPCE only: no high TDS completion fluids (per authorization letter).	OGC: No separate permit for reserve pit. DPCE: Terms of permitting for reserve pits incorporated in letter of authorization.
California	No degradation of ground-water quality; if waste is hazardous, detailed standards apply to the pits as "surface	Liners may or may not be required, depending on location and local regulations; in limited cases where fluids		Use of nonapproved additives and fluids renders the waste subject to regulation as a hazardous waste.	Regional Water Quality Control Boards (RWQCBs) have authority to permit, oversee management.

State	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/oversight
California (continued)	impoundments"; if non-hazardous, the waste "shall be disposed of in such a manner as not to cause damage to life, health, property, fresh water aquifers or surface waters, or natural resources, or be a menace to public safety."	contain hazardous materials, double liners required.			
Colorado	Prevent pollution (broadly defined) of State waters; prevent exceeding of stream standards.	Liners and leak detection systems generally reqd for pits with a capacity greater than 100 bbl/d and a TDS content greater than 5,000 ppm; liners also reqd in designated areas overlying domestic water supplies.		No prohibition on commingling of drilling muds and initial water production, but disposal of greater than 5 bbl/d produced water renders the reserve pit subject to regulations for pits receiving produced water; no wells drilled with oil-based muds.	Individual permit if pit receives more than 5 barrels fluid per day.
Kansas	Specific delineation of areas requiring liners (proposed).	No general requirement; liners may be required in geologically or hydrologically sensitive areas (e.g., over sandy soils); Commission may require observation trenches, holes, or monitoring wells.	1-ft freeboard (proposed regs).		General permits for pits operating for less than 1 year (extensions granted); individual permits granted unless denied within 10 days of application (proposed regs).

Table VII-1 (continued)

State	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/ oversight
Louisiana	Prevent contamination of aquifers, including USDWs, and protect surface water.	Liners not required for onsite reserve pits; liners (10^{-7} cm/sec) reqd for offsite commercial facilities.	2-ft freeboard, protection of surface water by levees, walls, and drainage ditches.	No produced water or waste oil at onsite facilities.	More stringent reqts (including financial respons.) for commercial facilities.
Michigan		Liners required when drilling with salt water-based drilling fluids; or when drilling through salt or brine-containing formations; in other areas, exceptions may be granted, but rarely are requested; liners must be 20 mil virgin PVC or its equivalent.		No salt cuttings as solids, oil, refuse, completion or test fluids.	Individual permit bond, and environmental assessment reqd.
New Mexico	Prevent contamination of surface and subsurface water.	Liners not required for onsite reserve pits; in the Northwest, liners may be required for commercial facilities.			Permits are reqd for centralized facilities with some exceptions.
Ohio	Prevent escape of produced water; prevent contamination of land, surface water, and ground water.	No requirement for liners, except where required on a site-specific basis in hydrogeologically sensitive areas.			

Table VII-1 (continued)

States	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/oversight
Oklahoma	Prevent pollution of surface and subsurface water, commercial pits must be sealed with an impervious material.	No liner requirement for reserve pits for wells using freshwater drilling muds, 30-mil liners (or metal tanks) reqd for pits containing "deleterious fluids other than freshwater drilling muds." 12-inch, 10^{-7} cm/sec soil liner for commercial pits; commercial pits must be at least 25 feet above highest aquifer, site-specific reqt for coml pits containing deleterious fluids.	18-inch freeboard and run-on controls; 36 inches for commercial pits.	More stringent reqts (i.e., liners) for fluids other than water-based muds provide an incentive to manage these wastes separately.	Permit not reqd for on-site pits; notification reqd for emergency and burn pits.
Texas	May not cause or allow pollution of surface or subsurface water.	Liners not required.		Use of reserve pits and mud circulation pits is restricted to drilling fluids, drill cuttings, sands, silts, wash water, drill stem test fluids, and blowout preventer test fluids	Reserve pits and mud circulation pits are authorized by rule without permits; individual permit reqd for coml facilities, drilling fluid storage pits (other than mud circulation pits), and drilling fluid disposal pits (other than reserve pits).

Table VII-1 (continued)

States	General statement of objective/purpose	Liners	Overtopping	Commingling provision	Permitting/ oversight
W. Virginia	Prevent seepage, leakage, or overflow and maintain pit integrity.	Liners not reqd, except where soil is not suitable to prevent seepage or leakage.	Adequate freeboard	No produced water, unused fracturing fluid or acid, compressor oil, refuse, diesel, kerosene, halogenated phenol, etc.	General permit, offsite discharge of fluids requires an individual permit.
Wyoming	Prevent pollution of streams and underground water and unreasonable damage to the land.	Liners not reqd except where the potential for communication between the pit contents and surface water or shallow ground water is high.		No chemicals that reduce the pit's fluid seal.	Individual permit reqd except for workover and completion pits containing oil and/or water; more stringent design reqts for commercial pits.

Table VII-2 Reserve Pit Closure/Waste Removal

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
Alaska	Must be operated with a fluid management plan and must be closed within 1 year after final disposal of drilling wastes in pit; or must be designed for 2 years' disposal and closed in that time period; numerous performance reqts added.	General permit for discharge of fluids to tundra; prior written approval reqd; specs and effluent monitoring for metals and conventional pollutants; only pits eligible are those that have received no drilling wastes since previous summer (last freeze-thaw cycle), to allow precipitation of contaminants.	Individual permit; compliance point is edge of the road for same specs as for land application (except pH); no requirement for freeze-thaw cycle.	See land application; specs same as AK WQS (except TDS) pending study to determine effect on wildlife.	General permit for N. Slope; prior written approval reqd; discharge must occur below the permafrost into a zone containing greater than 3,000 ppm TDS.
Arkansas (revisions due in '88)	OGC: No specific regulatory requirements. DPCE: within 60 days of rig's removal, reclaim to grade and reseed; fluids must be consigned to state-permitted disposal service (per authorization letter).	DPCE only: waste analysis and landowner's consent reqd for land application (per authorization letter).		Prohibited.	DPCE: prior approval reqd (per authorization letter).
California	When drilling operations cease, remove either (1) all wastes or (2) all free liquids and hazardous residuals.	Offsite disposal reqts depend on whether waste is "hazardous" (double liners), "designated" (single liner) or nonhazardous.		Permit reqd from RWQCB; disposal may not cause damage to surface water.	
Colorado	For dry and abandoned wells, within 6 months of a well's closure, decant the fluids, backfill and reclaim.	Dewatered sediment may be tilled into the ground.		Permits for discharge may be issued if effluent meets stream's classification standard.	

Table VII-2 (continued)

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
Kansas	As soon as practical, evaporate or dewater and backfill; 365 days, or sooner if specifically required by Commission (proposed).	Landfarming is prohibited; in-situ disposal may be prohibited in sensitive areas.	If approved by Kansas Department of Health and Environment.		Prohibited.
Louisiana	Within 6 months of completion of drilling or workover activities, fluids must be analyzed for pH, O&G, metals and salinity, and then removed; exemption for wells less than 5,000 ft deep if native mud used.	Onsite land treatment or trenching of fluids and land treatment, burial or solidification of nonfluids allowed provided specs are met (including pH, electrical conductivity, and certain metals).		Permits issued for discharge of wastewater from treated drilling site reserve pits, so long as limitations for oil and grease, TSS, metals, chlorides, pH are met. Dilution allowed to meet chloride limits.	Surface casing must be at least 200 ft below the lowest USDW.
Michigan	At closure, all free liquids must be removed and the residue encapsulated onsite or disposed of offsite.	In-situ encapsulation requires a 10-mil PVC cap 4 ft below grade; offsite disposal must be in a lined landfill with leachate collection and ground-water monitoring	Prohibited.	Prohibited.	Well must have production casing and injected fluid must be isolated below freshwater horizons; exception granted if, among other things, pressure gradient is less than 0.7 psi.
New Mexico		Pits are evaporated and residue generally buried onsite.		Prohibited.	

Table VII 2 (continued)

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
Ohio	Within 5 months of the commencement of drilling, backfill and remove concrete bases and drilling equipment, within 9 months, grade and revegetate area not reqd for production.	Drilling fluids may be disposed of by land application; pit solids may be buried onsite, except where history of ground-water problems		Permit reqd.	Standard well treatment fluids can be injected; same reqts as for annular produced water disposal; permit generally reqd
Oklahoma	Within 12 months of drilling operation's cessation, dewater and leave; 6-month extension for good cause; only 60 days allowed for circulating and fracture pits.	Landfarming of water-based muds is allowed; permit reqd; siting and rate application reqts, waste analysis, revegetation within 120 days		Prohibited.	Onsite injection allowed, approval reqd; surface casing must be set at least 200 ft below treatable water; limits on pressure so that vertical fractures will not extend to base of treatable water.
Texas	Within 30 days to 1 year from when drilling ceases (depending on the fluid's Cl content) dewater, backfill, and compact.	Landfarming prohibited for water-based drilling fluids having greater than 3,000 mg/L Cl and oil-based wastes; onsite burial prohibited for oil-based drilling fluids (but burial of solids obtained while using oil-based drilling fluid allowed).		Minor permit required for discharge of fluid fraction from treated reserve pits; prior notif. and 24-hour bioassay test reqd; discharge may not violate TX WQS or haz. metals limits; specs include O&G (15 mg/L), Cl (1,000 mg/L coastal, 500 mg/L in-land); TSS (50 mg/L), COD (200 mg/L), TDS (3000 mg/L)	One-time annular injection allowed; "minor permit" required; limits on surface injection pressure; casing set such that usable quality water protected to depth recommended by TWC.

Table VII-3 (continued)

State	Deadline/ general standard	Land disposal/ application	Road application	Surface water discharge	Annular injection
W. Virginia	Within 6 months from when drilling ceases.	Cuttings may be buried onsite; after physical treatment, fluids meeting specs can be applied to the land; specs include oil (no visible sheen on land) and Cl (25,000 mg/L), monitoring reqd for other parameters.			
Wyoming	Within 1 year of use, remove liquids and reclaim pit; reclamation bond released after pit closure inspected and approved.	Permit reqd for land application; discharge must meet water quality limits, including O&G (2,000 or 20,000 lb/acre, depending on whether soil incorporated), Cl (1,500 mg/L).	Permit reqd for road application; location and application reqts imposed through DEQ memorandum.	Prohibited, except where DEQ determines discharge will not cause sig. envir damage or contaminate public water supplies; application must include complete analysis, volume, location, and name of receiving stream.	One-time injection allowed under some conditions as in UIC permit.

Table VII-3 Produced Water Pit Design and Construction

State	General statement of objective/purpose	Liners	Exemptions	Permitting/oversight
Alaska	Produced water is a "drilling waste" and is subject to the same reqts as in Table VII-1.			
Arkansas (revisions due in '88)	No discharge into any water of the State (including ground water).	Pits must be lined or underlaid by tight soil; pits prohibited over porous soil; (DPCE authorization letter requires tanks).		Individual permit; application reqd within 30 days of producing waste.
California	Nondegradation of State waters; pits not permitted in natural drainage channels or where they may be in communication with freshwater-bearing aquifers.	Liners reqd where necessary to comply with the State's nondegradation policy; specific standards for construction/operation may be established by RWQCBs.		Subject to permitting authority of Regional WQCB.
Colorado	Prevent pollution (broadly defined) of State waters; prevent exceeding of stream standards.	Same as for reserve pits (for pits receiving more than 5 bbl/d 90% of the pits are lined; 2/3 clay, 1/3 synthetic)	Exemptions from liner requirement for pits overlying impermeable materials or receiving water with less than 5,000 ppm TDS.	Individual permit.
Kansas	Consideration of protection of soil and water resources from pollution.	Strict liner and seal requirements in conjunction with hydrogeologic investigation.		No permits issued for unlined pits.
Louisiana		All pits must be lined such that the hydraulic conductivity is less than 10^{-7} cm/sec.	Pits in certain coastal areas, provided they are part of a treatment train for oil and grease removal.	

State	General statement of objective/purpose	Liners	Exemptions	Permitting/oversight
Michigan	Brine cannot be run to earthen reservoirs or ponds.			
New Mexico		In the southeast, 30-mil liners with leak detection are reqd; in the northwest, liners are reqd over specified vulnerable aquifers.	Small-volume pits and pits in specified areas that are already saline and in areas without fresh water.	If liner required, individual permit after hearing.
Ohio	Pits must be liquid tight; waste cannot be stored for more than 180 days; pits may not be used for ultimate disposal.			Produced water disposal plan must be submitted.
Oklahoma	Pits must be sealed with an impervious material; in addition, offsite pits must contain fluids with less than 3,500 ppm Cl.	12-inch, 10^{-7} cm/sec soil liner for coml pits; site-specific liner reqt if coml pit contains deleterious fluids.		Individual permits required.
Texas	Permit for unlined pit denied unless operator conclusively shows pit will not pollute agricultural land, surface or subsurface water; emergency pits generally exempted.	Generally, all pits other than emergency pits require liners unless (1) there is no surface or subsurface water in the area, or (2) the pit is underlaid by a naturally occurring impervious barrier; liners required for emergency pits in sensitive areas.		Individual permit.
W. Virginia	Same as for reserve pits.	Same as for reserve pits.		Same as for reserve pits.
Wyoming		Liners not reqd except where the potential for communication between the pit contents and surface water or shallow ground water is high.		Individual permit reqd if pit receives more than 5 bbl/day produced water; area-wide permits also granted; individual permits and more stringent terms for commercial pits.

Table VII-4 Produced Water Surface Discharge Limits

State	Onshore	Coastal/tidal	Beneficial use	Permitting/oversight
Alaska				Produced water is subject to the discharge reqts for reserve pit fluids in Table VII-1.
Arkansas	Prohibited.	Not applicable.		
California	In some cases, produced waters ultimately disposed of in sumps are allowed to first be discharged into canals or ephemeral streams that carry the salt water to the sumps.	Policy for enclosed bays and estuaries prohibits discharge of materials of petroleum origin in sufficient quantities to be visible or in violation of waste discharge reqts; Ocean Plan sets limits for O&G, arsenic, total chromium, etc.	Discharge allowed to canals, ditches, and ephemeral streams before reuse; specs issued by one RWQCB include O&G (35 mg/L) and Cl (200 mg/L).	Permit reqd from RWQCB for beneficial use.
Colorado	Discharge must not cause pollution (broadly defined) of any waters of the state; must not cause exceeding of stream standards.	N/A	Specs for wildlife and agricultural use include O&G (10 mg/L) and TDS (5,000 mg/L, 30-day average).	Permit reqd from Water Quality Control Division of Department of Health.
Kansas	Prohibited.	N/A		Road application requires approval by Dept. of Health and Environment.
Louisiana	Discharges allowed into lower distributaries of Mississippi and Atchafalaya Rivers; discharges into waters of the State require a permit after 11/20/86; facility deemed in compliance except where an investigation or a complaint has been filed.	Discharge allowed if treated to remove residual O&G.		Individual permits for surface discharges required after 11/20/86.

Table VII-4 (continued)

State	Onshore	Coastal/tidal	Beneficial use	Permitting/oversight
Michigan	Prohibited.	Prohibited.	Specs for dust control. 3-yr study to determine if practice should be continued.	
New Mexico	Prohibited except in emergencies or for construction; application reqd.	N/A	Use as drinking water for cattle and in construction, no contaminant levels specified.	State approval for cattle watering and construction reqd
Ohio	Discharge must not cause pollution of any waters of the State.	N/A	Reqts for road spreading include a 12-ft buffer zone to prevent damage to water bodies.	Road or land spreading must be authorized by city/municipal resolution; NPDES permit reqd for onshore discharges.
Oklahoma	Prohibited.	N/A		
Texas	Prohibited, unless fresh.	Discharges allowed, but skimming required to prevent oil in tidal waters; testing for oil every 30-40 days.		Individual permit
W. Virginia	No discharge of salt water or other water unfit for domestic livestock into waters of State.	N/A	Road application allowed pending study.	NPDES permit reqd for onshore discharges; general permit for stripper wells expected mid-1987.
Wyoming	Specs include O&G (10 mg/L) and Cl (2,000 mg/L); no discharge of toxic substances at conc. toxic to humans, animals, or aquatic life.	N/A		NPDES permit reqd for surface discharges.

Table VII-5 Produced Water Injection Well Construction

State	Casing	MIT pressure and duration	MIT frequency	Abandoned wells
Alaska	Safe and appropriate casing, cemented to protect oil, gas, and fresh water; detailed casing specs.	30 min at 1,500 psi or 0.25 psi/ft times vertical depth of casing shoe, whichever is greater; max. pressure decline 10%.	Before operation; thereafter monthly reporting of casing-tubing annulus pressure.	1/4-mile area of review.
Arkansas	Well must be cased and cemented so as not to damage oil, gas, or fresh water.	Determined by AOGC on a case-by-case basis.	Before operation; thereafter every 5 years.	1/2-mile area of review.
California	Safe and appropriate casing; cementing specs.	From hydrostatic to the pressure reqd to fracture the injection zone or the proposed injection pressure, whichever occurs first; step rate test may be waived.	Within 3 months after injection commences and annually thereafter, after any anomalous rate or pressure change, or as requested by DOG.	1/4-mile fixed radius in combination with radial flow equation and documented geological features are used to define area of review.
Colorado	Safe and adequate casing or tubing to prevent leakage, and cemented so as not to damage oil, gas, or fresh water.	15 min at 300 psi or the minimum injection pressure, whichever is greater; max. variance 10%.	Before operation, thereafter every 5 years; exceptions for wells monitoring annulus pressure monthly.	1/4-mile area of review; notice to surface and working interest owners within 1 mile.
Kansas	Well must be cased and cemented to prevent damage to hydrocarbon sources or fresh and usable water.	For old wells, 100 psi; for new wells, 100 psi or the authorized pressure, whichever is greater; alternative tests allowed; 30-minute test.	Before operation; thereafter every 5 years	1/4-mile area of review.
Louisiana	Casing must be set through the deepest USDW and cemented to the surface.	For new wells, 30 min at 300 psi, or max. allowable pressure, whichever is greater; for converted wells, the lesser of 1,000 psi or max. allowable pressure, but no lower than 300 psi; max. variance of 5 psi.	Before operation; thereafter every 5 years.	1/4-mile area of review.

Table VII-5 (continued)

State	Casing	MIT pressure and duration	MIT frequency	Abandoned wells
Michigan	Casing and seal to prevent the loss of produced water into an unapproved formation.	30 min at 300 psi; 3% allowable bleedoff.	As scheduled by RA (Federally administered).	State program to plug abandoned wells.
New Mexico	Casing or tubing to prevent leakage and fluid movement from the injection zone.	15-30 min at 250-300 psi; max. variance 10%	Before operation, thereafter every 5 years; special test can be reqd more often; annulus monitoring required monthly.	State program to plug abandoned wells; 2 1/2-mile area of review, variance allowing no less than 1/4 mile; corrective action reqd to prevent migration through conduits.
Ohio	In addition to use of injection wells, annular disposal of produced water is allowed; max annular disposal 5-10 bbl/d; use only force of gravity; systems must be airtight.			
	Casing must be set at least 50 ft below the deepest USDW and must be cemented to the surface.	15 min at 300 psi, or max. allowable pressure, whichever is greater; max. decline 5%; alternative tests allowed.	Before operation; thereafter every 5 years.	1/4- to 1/2-mile area of review, depending on volume injected; well plugging fund.
Oklahoma	Casing must be set at least 90 ft below the surface or 50 ft below treatable water, whichever is lower, and must be cemented to the surface.	Same as Louisiana, except maximum bleedoff of 10%.	Before operation; thereafter every 5 years; exception for wells monitoring pressure monthly and reporting annually.	1/2-mile area of review; well plugging fund.
Texas	Surface casing cemented to surface; tubing and cemented casing string to isolate injection zone.	Test at 500 psig, or max. allowable pressure, whichever is less, but at least 200 psig; max. decline of 10%; once pressure stabilizes, 30 minutes with no variation.	Before injection, after workover, and thereafter every 5 years (exception for wells monitoring annulus pressure monthly and rpt'g annually, or for other viable alternative test).	1/4-mile area of review; notice to surface owners and offset operators; well plugging fund (main source: $100 drilling permit fee).

Table VII-5 (continued)

State	Casing	MIT pressure and duration	MIT frequency	Abandoned wells
W. Virginia		20 min at 1.5 to 2 times the injection pressure; max. variance 5%.	Every 5 years.	
Wyoming	Surface casing must be set below freshwater sources; casing cemented to the surface.	Same as Louisiana.	Before injection, thereafter every 5 years.	Notice to landowners and operators within 1/2 mile, 1/4-mile area of review

Table VII-6 Well Abandonment/Plugging

States	Plugging deadline	Plugging oversight
Alaska	1 year following end of operator's activity within the field; if well not completed, must be abandoned or suspended before removal of drilling equipment; bridge plugs reqd for suspended wells.	Plugging method must be approved before beginning work; indemnity bond released after approval of well abandonment.
Arkansas	If not completed, must be abandoned/plugged before drilling equip. is released form the drilling operation; no time limit for temporary abandonment of properly cased well.	Plugging permit; onsite supervision by AOGC official; bond or other evidence of finanacial responsibility reqd, and released only after plugging/abandonment completed.
California	6 months after drilling activity ceases or 2 years after drilling equipment is removed; unless temp. abandonment of properly cased well.	Indemnity bond released after proper abandonment or completion is ensured.
Colorado	Generally, 6 months after production ceases; extensions require semi-annual status report.	Plugging method must be approved; COGC must have opportunity to witness; blanket or individual bond reqd.
Kansas	90 days after operations cease; where temporary abandonment, annual extensions require notice and status reports.	Plugging plan reqd before beginning work; report reqd after completion.
Louisiana	Within 90 days of notice in "Inactive Well Report" unless a plan is submitted describing the well's future use.	
Michigan	Within 60 days after cessation of drilling activities; within 1 year after cessation of production (with extensions, if sufficient reason to retain well).	Plugging method must be approved.

Table VII-6 (continued)

State	Plugging deadline	Plugging oversight
New Mexico	Generally, 6 months; extensions granted for up to 2 yr at a time	Well plugging plan must be approved; plugging bond released after inspection and Director approval.
Ohio	Immediately upon abandonment of a dry hole, without undue delay after prod ceases, extensions provided for 6 months.	Before plugging, approval reqd; after plugging, report reqd including identity of witnesses; liability insurance reqd; surety bond forfeited if noncompliance with regs.
Oklahoma	Where prod. casing has been run, 1 year after cessation of drilling (numerous exceptions); less time where no, or only surface, casing run; special rules for temporary abandonment.	Plugging must be supervised by an authorized rep. of the Conservation Division; plugging report reqd; proof of financial ability to comply with plugging reqt.
Texas	Within 90 days after drilling or operations cease, except where cessation occurred in '66 or '67 (1 year); extensions at Director's discretion (if no pollution hazard) with plugging bond or letter of credit or plan to use for enhanced recovery.	Before plugging, notification and approval reqd, after plugging, report reqd; operator must be present during plugging.
W Virginia	Prompt plugging reqd if dry holes and wells not in use for 12 mo; extensions for good cause.	Plugging bond and notif. to the Director and nearby coal operators reqd.
Wyoming	Approval from the State reqd if well is "temporarily abandoned" for more than 1 year.	Before plugging, approval reqd; after plugging, report reqd; well plugging bond released after the State inspection.

Table VII-7 State Enforcement Matrix

State	Gas Production	Oil Production	Gas wells	Oil wells	Injection wells	New wells	Agency	Personnel*
Alaska	316,000 Mmcf 1986	681,309,821 bbl 1986	104	1,191	472 Class II 425 EOR 47 Disposal	100 new onshore wells completed in 1985	Oil and Gas Conservation Commission Department of Environmental Conservation	8 enforcement positions 8 enforcement positions
Arkansas	194,483 Mmcf 1985	19,715,691 bbl 1985	2,492	9,490	1,211 Class II 239 EOR 972 Disposal	1,055 new wells completed in 1985	Arkansas Oil and Gas Commission Department of Pollution Control and Ecology	7 enforcement positions 2 enforcement positions
California	493,000 Mmcf 1985	423,900,000 bbl 1985	1,566	55,079	11,066 Class II 10,047 EOR 1,019 Disposal	3,413 new wells completed in 1985	Conservation Dept., Division of Oil and Gas Department of Fish and Game	31 enforcement positions
Kansas	466,600 Mmcf 1984	75,723,000 bbl 1984	12,680	57,633	14,902 Class II 9,366 EOR 5,536 Disposal	6,025 new wells completed in 1985	Kansas Corporation Commission	30 enforcement positions
Louisiana	5,867,000 Mmcf 1984	449,545,000 bbl 1984	14,436	25,823	4,436 Class II 1,283 EOR 3,153 Disposal	5,447 new onshore wells completed 1985	Department of Environmental Quality Office of Conservation - Injection and Mining	32 enforcement positions 36 enforcement positions
New Mexico	893,300 Mmcf 1985	78,500,000 bbl 1985	18,308	21,986	3,871 Class II 3,508 EOR 363 Disposal	1,747 new wells completed in 1985	Energy and Minerals Department, Oil Conservation Division	10 enforcement positions
Ohio	182,200 Mmcf 1985	14,987,592 bbl 1985	31,343	29,210	3,956 Class II 127 EOR 3,829 Disposal	6,297 new wells completed in 1985	Ohio Department of Natural Resources, Division of Oil and Gas	66 enforcement positions
Oklahoma	1,996,000 Mmcf 1984	153,250,000 bbl 1984	23,647	99,030	22,803 Class II 14,901 EOR 7,902 Disposal	9,176 new wells completed in 1985	Oklahoma Corporation Commission	52 enforcement positions
Pennsylvania	166,000 Mmcf 1984	4,825,000 bbl 1984	24,050	20,739	6,183 Class II 4,315 EOR 1,868 Disposal	4,627 new wells completed in 1985	Department of Environmental Resources, Bureau of Oil and Gas Management	34 enforcement positions
Texas	5,805,000 Mmcf 1985	830,000,000 bbl 1985	68,811	210,000	53,141 Class II 45,223 EOR 7,918 Disposal	25,721 new wells completed in 1985	Texas Railroad Commission	120 enforcement positions
West Virginia	142,500 Mmcf 1986	3,600,000 bbl 1986	32,500	15,895	761 Class II 687 EOR 74 Disposal	1,839 new wells completed in 1985	West Virginia Department of Energy	15 enforcement positions
Wyoming	597,896 Mmcf 1985	130,984,917 bbl 1985	2,220	12,218	5,880 Class II 5,257 EOR 623 Disposal	1,735 new wells completed in 1985	Oil and Gas Conservation Commission Department of Environmental Quality	7 enforcement positions 4.5 enforcement positions

*Only field staff are included in total enforcement positions.

Table VII-8 BLM Enforcement Matrix*

Office location	Other States for which office is responsible	Producing oil and gas leases	Nonproducing oil and gas leases**	Personnel (for producing leases only)
Alaska		43	8,443	1 enforcement position
California		305	1,383	7 enforcement positions
Colorado		3,973	4,463	10 enforcement positions
Idaho		0	471	0 enforcement positions
Mississippi		116	1,519	
	Alabama	12	567	
	Arkansas	161	1,099	
	Florida	1	0	
	Kentucky	13	65	
	Louisiana	121	487	
	Virginia	1	523	
	Total	425	4,260	3 enforcement positions
Montana		958	4,721	
	North Dakota	456	1,991	
	South Dakota	98	572	
	Total	1,512	7,284	12 enforcement positions
Nevada		43	3,045	1 enforcement position
New Mexico		5,725	9,306	
	Arizona	10	386	
	Kansas	150	227	
	Oklahoma	2,767	2,754	
	Texas	61	279	
	Total	8,713	12,952	43 enforcement positions
Oregon		0	1,513	0
Utah		1,654	7,222	10 enforcement positions
Wisconsin		0	0	
	Maryland	2	11	
	Michigan	28	603	
	Missouri	1	6	
	Ohio	33	69	
	Pennsylania	6	1	
	West Virginia	46	54	
	Total	116	844	1 enforcement position
Wyoming		5,037	28,044	
	Nebraska	42	582	
	Total	5,079	28,626	27 enforcement positions
	Total	22,037	102,251	115 enforcement positions

* Oil and gas inspectors working in the field as of March 30, 1987. At that time there were eight vacancies nationwide.

** Includes leases that have never been drilled, have been drilled and abandoned, or are producing wells that have been temporarily shut down.

REFERENCES

43 CFR 3100 (entire group).

U.S. Bureau of Land Management. (Not dated.) Federal Onshore Oil and Gas Leasing and Operating Regulations.

U.S. Bureau of Land Management. NTL-2B.

U.S. Department of the Interior - Geological Survey Division. (Not dated.) Notice to Lessees and Operators of Federal and Indian Oil and Gas Leases (NTL-2B).

Personal communication with Mr. Steve Spector, September 23, 1986.

CHAPTER VIII

CONCLUSIONS

From the analysis conducted for this report, it is possible to draw a number of general conclusions concerning the management of oil and gas wastes. These conclusions are presented below.

Available waste management practices vary in their environmental performance.

Based on its review of current and alternative waste management practices, EPA concludes that the environmental performance of existing waste management practices and technologies varies significantly. The reliability of waste management practices will depend largely on the environmental setting. However, some methods will generally be less reliable than others because of more direct routes of potential exposure to contaminants, lower maintenance and operational requirements, inferiority of design, or other factors. Dependence on less reliable methods can in certain vulnerable locations increase the potential for environmental damage related to malfunctions and improper maintenance. Examples of technologies or practices that are less reliable in locations vulnerable to environmental damage include:

- Annular disposal of produced water (see damage case OH 38, page IV-16);
- Landspreading or roadspreading of reserve pit contents (see damage case WV 13, page IV-24);
- Use of produced water storage pits (see damage case AR 10, page IV-36); and

- Surface discharges of drilling waste and produced water to sensitive systems such as estuaries or ephemeral streams (see damage cases TX 55, page IV-49; TX 31, page IV-50; TX 29, page IV-51; WY 07, page IV-60; and CA 21, page IV-68).

Any program to improve management of oil and gas wastes in the near term will be based largely on technologies and practices in current use.

Current technologies and practices for the management of wastes from oil and gas operations are well established, and their environmental performance is generally understood. Improvements in State regulatory requirements over the past several years are tending to increase use of more desirable technologies and practices and reduce reliance on others. Examples include increased use of closed systems and underground injection and reduced reliance on produced water storage and disposal pits.

Long-term improvements in waste management need not rely, however, purely on increasing the use of better existing technology. The Agency does foresee the possibility of significant technical improvements in future technologies and practices. Examples include incineration and other thermal treatment processes for drilling fluids; conservation, recycling, reuse, and other waste minimization techniques; and wet air oxidation and other proven technologies that have not yet been applied to oil and gas operations.

Because of Alaska's unique and sensitive tundra environment, there has been special concern about the environmental performance of waste management practices on the North Slope. Although there are limited and preliminary data that indicate some environmental impacts may occur, these data and EPA's initial analysis do not indicate the need to curtail current or future oil exploration, development, and production operations on the North Slope. However, there is a need for more environmental data

on the performance of existing technology to provide assurance that future operations can proceed with minimal possible adverse impacts on this sensitive and unique environment. The State of Alaska has recently enacted new regulations which will provide additional data on these practices.

EPA is concerned in particular about the environmental desirability of two waste management practices used in Alaska: discharge of reserve pit supernatant onto tundra and road application of reserve pit contents as a dust suppressant. Available data suggest that applicable discharge limits have sometimes been exceeded. This, coupled with preliminary biological data on wildlife impacts and tundra and surface water impairment, suggests the need for further examination of these two practices with respect to current and future operations. The new regulations recently enacted by the State of Alaska should significantly reduce the potential for tundra and wildlife impacts.

Increased segregation of waste may help improve management of oil and gas wastes.

The scope of the exemption, as interpreted by EPA in Chapter II of this report, excludes certain relatively low-volume but possibly high-toxicity wastes, such as unused pipe dope, motor oil, and similar materials. Because some such wastes could be hazardous and could be segregated from the large-volume wastes, it may be appropriate to require that they be segregated and that some of these low-volume wastes be managed in accordance with hazardous waste regulations. While the Agency recognizes that small amounts of these materials may necessarily become mixed with exempt wastes through normal operations, it seeks to avoid any deliberate and unnecessary use of reserve pits as a disposal mechanism. Segregation of these wastes from high-volume exempt wastes appears to be desirable and should be encouraged where practical.

Although this issue is not explicitly covered in Chapter VII, EPA is aware that some States do require segregation of certain of these low-volume wastes. EPA does not have adequate data on which to judge whether these State requirements are adequate in coverage, are enforceable, are environmentally effective, or could be extended to general operations across the country. The Agency concludes that further study of this issue is desirable.

Stripper operations constitute a special subcategory of the oil and gas industry.

Strippers cumulatively contribute approximately 14 percent of total domestic oil production. As such, they represent an economically important component of the U.S. petroleum industry. Two aspects of the stripper industry raise issues of consequence to this study.

First, generation of production wastes by strippers is more significant than their total petroleum production would indicate. Some stripper wells yield more than 100 barrels of produced water for each barrel of oil, far higher on a percentage production basis than a typical new well, which may produce little or no water for each barrel of oil.

Second, stripper operations as a rule are highly sensitive to small fluctuations in market prices and cannot easily absorb additional costs for waste management.

Because of these two factors--inherently high waste-production rates coupled with economic vulnerability--EPA concludes that stripper operations constitute a special subcategory of the oil and gas industry that should be considered independently when developing recommendations for possible improvements in the management of oil and gas wastes. In

the event that additional Federal regulatory action is contemplated, such special consideration could indicate the need for separate regulatory actions specifically tailored to stripper operations.

Documented damage cases and quantitative modeling results indicate that, when managed in accordance with State and Federal requirements, exempted oil and gas wastes rarely pose significant threats to human health and the environment.

Generalized modeling of human health risks from current waste management practices suggests that risks from properly managed operations are low. The damage cases researched in the course of this project, however, indicate that exempt wastes from oil and gas exploration, development, and production can endanger human health and cause environmental damage when managed in violation of existing State requirements.

Damage Cases

In a large portion of the cases developed for this study, the types of mismanagement that lead to such damages are illegal under current State regulations although a few were legal under State programs at the time when the damage originally occurred. Evidence suggests that violations of regulations do lead to damages. It is not possible to determine from available data how frequently violations occur or whether violations would be less frequent if new Federal regulations were imposed.

Documented damages suggest that all major types of wastes and waste management practices have been associated to some degree with endangerment of human health and damage to the environment. The principal types of wastes responsible for the damage cases include general reserve pit wastes (primarily drilling fluids and drill cuttings,

but also miscellaneous wastes such as pipe dope, rigwash, diesel fuel, and crude oil); fracturing fluids; production chemicals; waste crude oil; produced water; and a variety of miscellaneous wastes associated with exploration, development, or production. The principal types of damage sometimes caused by these wastes include contamination of drinking-water aquifers and foods above levels considered safe for consumption, chemical contamination of livestock, reduction of property values, damage to native vegetation, destruction of wetlands, and endangerment of wildlife and impairment of wildlife habitat.

Risk Modeling

The results of the risk modeling suggest that of the hundreds of chemical constituents detected in both reserve pits and produced fluids, only a few from either source appear to be of concern to human health and the environment via ground-water and surface water pathways. The principal constituents of potential concern, based on an analysis of their toxicological data, their frequency of occurrence, and their mobility in ground water, include arsenic, benzene, sodium, chloride, boron, cadmium, chromium, and mobile salts. All of these constituents were included in the quantitative risk modeling; however, boron, cadmium, and chromium did not produce risks or resource damages under the conditions modeled.

For these constituents of potential concern, the quantitative risk modeling indicates that risks to human health and the environment are very small to negligible when wastes are properly managed. However, although the risk modeling employed several conservative assumptions, it was based on a relatively small sample of sites and was limited in scope to the management of drilling waste in reserve pits, the underground injection of produced water, and the surface water discharge of produced water from stripper wells. Also, the risk analysis did not consider

migration of produced water contaminants through fractures or unplugged or improperly plugged and abandoned wells. Nevertheless, the relatively low risks calculated by the risk modeling effort suggest that complete adherence to existing State requirements would preclude most types of damages.

Damages may occur in some instances even where wastes are managed in accordance with currently applicable State and Federal requirements.

There appear to be some instances in which endangerment of human health and damage to the environment may occur even where operations are in compliance with currently applicable State and Federal requirements.

Damage Cases

Some documented damage cases illustrate the potential for human health endangerment or environmental damage from such legal practices as discharge to ephemeral streams, surface water discharges in estuaries in the Gulf Coast region, road application of reserve pit contents and discharge to tundra in the Arctic, annular disposal of produced waters, and landspreading of reserve pit contents.

Risk Modeling

For the constituents of potential concern, the quantitative evaluation did indicate some situations (less than 5 percent of those studied) with carcinogenic risks to maximally exposed individuals higher then 1 in 10,000 ($1x10^{-4}$) and sodium levels in excess of interim limits for public drinking water supplies. Although these higher risks resulted only under conservative modeling assumptions, including high (90th percentile) concentration levels for the toxic constituents, they do indicate potential for health or environmental impairment even under the

general assumption of compliance with standard waste management procedures and applicable State and Federal requirements. Quantitative risk modeling indicates that there is an extremely wide variation (six or more orders of magnitude) in health and environmental damage potential among different sites and locations, depending on waste volumes, wide differences in measured toxic constituent concentrations, management practices, local hydrogeological conditions, and distances to exposure points.

Unplugged and improperly plugged abandoned wells can pose significant environmental problems.

Documentation assembled for the damage cases and contacts with State officials indicate that ground-water damages associated with unplugged and improperly plugged abandoned wells are a significant concern. Abandoned disposal wells may leak disposed wastes back to the surface or to usable ground water. Abandoned production wells may leak native brine, potentially leading to contamination of usable subsurface strata or surface waters.

Many older wells, drilled and abandoned prior to current improved requirements on well closure, have never been properly plugged. Many States have adequate regulations currently in place; however, even under some States' current regulations, wells are abandoned every year without being properly plugged.

Occasionally companies may file for bankruptcy prior to implementing correct plugging procedures and neglect to plug wells. Even when wells are correctly plugged, they may eventually leak in some circumstances in the presence of corrosive produced waters. The potential for environmental damage occurs wherever a well can act as a conduit between usable ground-water supplies and strata containing water with high

chloride levels. This may occur when the high-chloride strata are pressurized naturally or are pressurized artificially by disposal or enhanced recovery operations, thereby allowing the chloride-rich waters to migrate easily into usable ground water.

Discharges of drilling muds and produced waters to surface waters have caused locally significant environmental damage where discharges are not in compliance with State and Federal statutes and regulations or where NPDES permits have not been issued.

Damage cases indicate that surface water discharges of wastes from exploration, development, and production operations have caused damage or danger to lakes, ephemeral streams, estuaries, and sensitive environments when such discharges are not carried out properly under applicable Federal and State programs and regulations. This is particularly an issue in areas where operations have not yet received permits under the Federal NPDES program, particularly along the Gulf Coast, where permit applications have been received but permits have not yet been issued, and on the Alaskan North Slope, where no NPDES permits have been issued.

For the Nation as a whole, Rrgulation of all oil and gas field wastes under unmodified Subtitle C of RCRA would have a substantial impact on the U.S. economy.

The most costly hypothetical hazardous waste management program evaluated by EPA could reduce total domestic oil production by as much as 18 percent by the year 2000. Because of attendant world price increases, this would result in an annual direct cost passed on to consumers of over $6 billion per year. This scenario assumes that 70 percent of all drilling and production wastes would be subject to the current requirements of Subtitle C of RCRA. If only 10 percent of drilling wastes and produced waters were found to be hazardous, Subtitle C regulation would result in a decline of 4 percent in U.S. production and

a $1.2 billion cost increase to consumers, compared with baseline costs, in the year 2000.

EPA also examined the cost of a Subtitle C scenario in which produced waters injected for the purpose of enhanced oil recovery would be exempt from Subtitle C requirements. This scenario yielded production declines ranging from about 1.4 to 12 percent and costs passed on to consumers ranging from $0.7 to $4.5 billion per year, depending on whether 10 percent or 70 percent of the wastes (excluding produced waters injected for enhanced oil recovery) were regulated as hazardous wastes.

These Subtitle C estimates do not, however, factor in all of the Hazardous and Solid Waste Act Amendments relating to Subtitle C land disposal restrictions and corrective action requirements currently under regulatory development. If these two requirements were to apply to oil and gas field wastes, the impacts of Subtitle C regulation would be substantially increased.

The Agency also evaluated compliance costs and economic impacts for an intermediate regulatory scenario in which moderately toxic drilling wastes and produced waters would be subject to special RCRA requirements less stringent than those of Subtitle C. Under this scenario, affected drilling wastes would be managed in pits with synthetic liners, caps, and ground-water monitoring programs and regulated produced waters would continue to be injected into Class II wells (with no surface discharges allowed for produced waters exceeding prescribed constituent concentration limits). This scenario would result in a domestic production decline, and a cost passed on to consumers in the year 2000, of 1.4 percent and $400 million per year, respectively, if 70 percent of

the wastes were regulated. If only 10 percent of the wastes were subject to regulation, this intermediate scenario would result in a production decline of less than 1 percent and an increased cost to consumers of under $100 million per year.

The economic impact analysis also estimates affects on U.S. foreign trade and State tax revenues. By the year 2000, based on U.S. Department of Energy models, the EPA cost results projected an increase in national petroleum imports ranging from less than 100 thousand to 1.1 million barrels per day and a corresponding increase in the U.S. balance of payments deficit ranging from less than $100 thousand to $18 billion annually, depending on differences in regulatory scenarios evaluated. Because of the decline in domestic production, aggregated State tax revenues would be depressed by an annual amount ranging from a few million to almost a billion dollars, depending on regulatory assumptions.

Regulation of all exempt wastes under full, unmodified RCRA Subtitle C appears unnecessary and impractical at this time.

There appears to be no need for the imposition of full, unmodified RCRA Subtitle C regulation of hazardous waste for all high-volume exempt oil and gas wastes. Based on knowledge of the size and diversity of the industry, such regulations could be logistically difficult to enforce and could pose a substantial financial burden on the oil and gas industry, particularly on small producers and stripper operations. Nevertheless, elements of the Subtitle C regulatory program may be appropriate in select circumstances. Reasons for the above tentative conclusion are described below.

The Agency considers imposition of full, unmodified Subtitle C regulations for all oil and gas exploration, development, and production wastes to be <u>unnecessary</u> because of factors such as the following.

- Damages and risks posed by oil and gas operations appear to be linked, in the majority of cases, to violations of existing State and Federal regulations. This suggests that implementation and enforcement of existing authorities are critical to proper management of these wastes. Significant additional environmental protection could be achieved through a program to enhance compliance with existing requirements.

- State programs exist to regulate the management of oil and gas wastes. Although improvements may be needed in some areas of design, implementation, or enforcement of these programs, EPA believes that these deficiencies are correctable.

- Existing Federal programs to control underground injection and surface water discharges provide sufficient legal authority to handle most problems posed by oil and gas wastes within their purview.

The Agency considers the imposition of full Subtitle C regulations for all oil and gas exploration, development, and production wastes to be impractical because of factors such as the following:

- EPA estimates that the economic impacts of imposition of full Subtitle C regulations (excluding the corrective action and land disposal restriction requirements), as they would apply without modification, would significantly reduce U.S. oil and gas production, possibly by as much as 22 percent.

- If reserve pits were considered to be hazardous waste management facilities, requiring permitting as Subtitle C land disposal facilities, the administrative procedures and lengthy application processes necessary to issue these permits would have a drastic impact on development and production.

- Adding oil and gas operations to the universe of hazardous waste generators would potentially add hundreds of thousands of sites to the universe of hazardous waste generators, with many thousands of units being added and subtracted annually.

- Manifesting of all drilling fluids and produced waters offsite to RCRA Subtitle C disposal facilities would pose difficult logistical and administrative problems, especially for stripper operations, because of the large number of wells now in operation.

States have adopted variable approaches to waste management.

State regulations governing proper management of Federally exempt oil and gas wastes vary to some extent to accommodate important regional differences in geological and climatic conditions, but these regional environmental variations do not fully explain significant variations in the content, specificity, and coverage of State regulations. For example, State well-plugging requirements for abandoned production wells range from a requirement to plug within 6 months of shutdown of operations to no time limit on plugging prior to abandonment.

Implementation of existing State and Federal requirements is a central issue in formulating recommendations in response to Section 8002(m).

A preliminary review of State and Federal programs indicates that most States have adequate regulations to control the management of oil and gas wastes. Generally, these State programs are improving. Alaska, for example, has just promulgated new regulations. It would be desirable, however, to enhance the implementation of, and compliance with, certain waste management requirements.

Regulations exist in most States to prohibit the use of improper waste management practices that have been shown by the damage cases to lead to environmental damages and endangerment of human health. Nevertheless, the extent to which these regulations are implemented and enforced must be one of the key factors in forming recommendations to Congress on appropriate Federal and non-Federal actions.

CHAPTER IX

RECOMMENDATIONS

Following public hearings on this report, EPA will draw more specific conclusions and make final recommendations to Congress regarding whether there is a need for new Federal regulations or other actions. These recommendations will be made to Congress and the public within 6 months of the publication of this report.

Use of Subtitle D and other Federal and State authorities should be explored as a means for implementing any necessary additional controls on oil and gas wastes.

EPA has concluded that imposition of full, unmodified RCRA Subtitle C regulation of hazardous waste for all exempt oil and gas wastes may be neither desirable nor feasible. The Agency believes, however, that further review of the current and potential additional future use of other Federal and State authorities (such as Subtitle D authority under RCRA and authorities under the Clean Water Act and the Safe Drinking Water Act) is desirable. These authorities could be appropriate for improved management of both exempt and nonexempt, high-volume or low-volume oil and gas wastes.

EPA may consider undertaking cooperative efforts with States to review and improve the design, implementation, and enforcement of existing State and Federal programs to manage oil and gas wastes.

EPA has concluded that most States have adequate regulations to control most impacts associated with the management of oil and gas wastes, but it would be desirable to enhance the implementation of, and compliance with, existing waste management requirements. EPA has also

concluded that variations among States in the design and implementation of regulatory programs warrant review to identify successful measures in some States that might be attractive to other States. For example, EPA may want to explore whether changes in State regulatory reporting requirements would make enforcement easier or more effective. EPA therefore recommends additional work, in cooperation with the States, to explore these issues and to develop improvements in the design, implementation, and enforcement of State programs.

During this review, EPA and the States should also explore nonregulatory approaches to support current programs. These might include development of training standards, inspector training and certification programs, or technical assistance efforts. They might also involve development of interstate commissions or other organizational approaches to address waste management issues common to operations in major geological regions (such as the Gulf Coast, Appalachia, or the Southwest). Such commissions might serve as a forum for discussion of regional waste management efforts and provide a focus for development and delivery of nonregulatory programs.

The industry should explore the potential use of waste minimization, recycling, waste treatment, innovative technologies, and materials substitution as long-term improvements in the management of oil and gas wastes.

Although in the near term it appears that no new technologies are available for making significant technical improvements in the management of exempt wastes from oil and gas operations, over the long term various innovative technologies and practices may emerge. The industry should explore the use of innovative approaches, which might include conservation and waste minimization techniques for reducing generation of drilling fluid wastes, use of incineration or other treatment technologies, and substitution of less toxic compounds wherever possible in oil and gas operations generally.

Damage Cases Report Form and Summary

File Ref# WV 17 *State* WV

yes *Nearest City or Town* Ripley

Region 2 *County/Parish* Jackson

Proof Category *Administrative* 1 *Legal* *Scientific/technica* 1 *0 = no 1 = yes*

Description of Operation

Production Area Appalachian Basin *(basin, region, etc.)*

Production Type Gas *(oil, gas, injection well, etc.)*

Production Category Development *(exploration, development, production, or other)*

Description of Operation

In 1982 Kaiser Gas Co. drilled a gas well on the property of Mr. James Parsons. The well was fractured using a typical fracturing fluid or gel. The residual fracturing fluid migrated into Mr. Parson's water well, drilled to a depth of 416ft. (The gas well is located less than 1000 ft. from the water well.) By 1984, the water well was unfit for domestic use and an alternate source of water had to be found.

Description of Waste and Damage

Pathway of Contamination *(yes/no)* *Ground Water* yes *Surf. Water* *Soil*

Damage Source gas well *(reserve, holding or emergency pit; tank, well, battery; spill; injection well; blowdown, etc.)*

Areal Extent

Waste Stream fracturing fluid or gel *(mud, brine, produced water, workover fluid, frac fluid, etc.)*

Waste Analysis Well water was analyzed and found to contain high levels of fluoride, sodium, iron, manganese. The water had a hydrocarbon odor indicating the presence of gas. Dark and light gelatinous material (fracturing fluid), was found along with white fibers. *(describe nature of available analysis, cite key numbers if available)*

Waste Volume Released NA *(barrels, gallons, etc.)*

3/4/87&

Areal Extent NA *(acres)*

Date of Release 1982 *(release may be ongoing, recently reported, etc.)*

Duration Approximately 12 hours *(comment as needed)*

Affected Biota *(yes/no)* *Fauna* ☐ *Flora* ☐ *Human Health* yes

Damage Description When fracturing the Kaiser gas well on Mr. James Parson's property, fractures were created allowing migration of fracture fluid from the gas well to Mr. Parson's water well. This fracture fluid, along with natural gas was present in Mr. Parson's water rendering it unusable. The contamination has since passed through the water well, but is still contained in the groundwater.

Violations State Regs. 0 *(0=No 1=Yes) at time of damage*

Compliance Issues No apparent compliance issues - no laws dictating proximity of oil and gas wells to water wells - no maximum pressure dictated for fracturing oil and gas wells.

Documentation Three lab reports containing analusis of water well. Letter from J. E. Rosencrance, Environmental Health Services Lab, to P. E. Merritt, Sanitarian, Jackson County. Letter from P. R. Merritt to J. E. Rosencrance requesting analysis. Letter from M. W. Lewis, Office of Oil and Gas to James Parsons stating state cannot help in recovering expenses - must file civil suit. Water well inspection report - complaint. Sample report forms.

3/4/87&

IV-35
(Rev 8-81)

State of West Virginia
Department of Mines
Oil and Gas Division

Date October 26, 1982
Operator's
Well No. KLM #244
Farm James Parsons
API No. 47 - 035 - 1746

WELL OPERATOR'S REPORT
OF
DRILLING, FRACTURING AND/OR STIMULATING, OR PHYSICAL CHANGE

WELL TYPE: Oil ___ / Gas X / Liquid Injection ___ / Waste Disposal ___ /
(If "Gas," Production X / Underground Storage ___ / Deep ___ / Shallow X /)

LOCATION: Elevation: 865' Watershed Straight Run
District: Ripley County Jackson Quadrangle Ripley

COMPANY Kaiser Exploration and Mining Company
ADDRESS P. O. Box 8, Ravenswood, WV 26164
DESIGNATED AGENT R. A. Pryce
ADDRESS P. O. Box 8, Ravenswood, WV 26164
SURFACE OWNER James Parsons
ADDRESS Spencer Road, Ripley, WV 25271
MINERAL RIGHTS OWNER Same
ADDRESS
OIL AND GAS INSPECTOR FOR THIS WORK Deo Mace ADDRESS Rt. 1, Box 5, Sandridge, WV
PERMIT ISSUED 8/03/82
DRILLING COMMENCED 8/19/82
DRILLING COMPLETED 8/25/82
IF APPLICABLE: PLUGGING OF DRY HOLE ON CONTINUOUS PROGRESSION FROM DRILLING OR REWORKING. VERBAL PERMISSION OBTAINED ON

Casing & Tubing	Used in Drilling	Left in Well	Cement fill up Cu. ft.
Size 20-16 Cond.			
13-10"		251'	150 sks
9 5/8			
8 5/8			
7		2437	165 sks
5 1/2			
4 1/2		4534	200 sks
3			
2			
Liners used			

GEOLOGICAL TARGET FORMATION Devonian Brown Shale Depth 3692' feet
Depth of completed well 4572' feet Rotary X / Cable Tools
Water strata depth: Fresh ___ feet; Salt ___ feet
Coal seam depths: ___ Is coal being mined in the area? ___

OPEN FLOW DATA
Producing formation Devonian Brown Shale Pay zone depth 4216'-4364' feet
Gas: Initial open flow N/A Mcf/d Oil: Initial open flow -- Bbl/d
Final open flow 104 Mcf/d Final open flow -- Bbl/d
Time of open flow between initial and final tests -- hours
Static rock pressure 1000 psig(surface measurement) after -- hours shut in
(If applicable due to multiple completion--)
Second producing formation ___ Pay zone depth ___ feet
Gas: Initial open flow ___ Mcf/d Oil: Initial open flow ___ Bbl/d
Final open flow ___ Mcf/d Oil: Final open flow ___ Bbl/d
Time of open flow between initial and final tests ___ hours
Static rock pressure ___ psig(surface measurement) after ___ hours shut in

JACK-1746

(Continue on reverse side)

FORM IV-35
(REVERSE)

DETAILS OF PERFORATED INTERVALS, FRACTURING OR STIMULATING, PHYSICAL CHANGE, ETC.

8/30/82 Devonian Brown Shale Perforations: 4216'-4364' shot selectively with 25 holes; 0.39" diameter.

8/31/82 Devonian Brown Shale Fracture: 60,000# of 20/40 sand; treatment pressure: 2500 psig-3100 psig; ISIP; 1200 psig; total of 318 bbl of water and 760,000 SCF of nitrogen.

WELL LOG

FORMATION COLOR HARD OR SOFT	TOP FEET	BOTTOM FEET	REMARKS Including indication of all fresh and salt water, coal, oil and gas
Sandstone & Shale	0	1214	
Sandstone	1214	1337	
Sandstone & Shale	1337	1773	
Limestone	1773	2060	
Sandstone & Shale	2060	2141	
Shale	2141	2513	
Coffee Shale	2513	2536	
Berea Sandstone	2536	2542	S/g @ 2539'
Shale	2542	3692	S/g @ 3467',3488',3552',3567', 3629',3655'
Brown Shale	3692	4353	S/g @ 3918',3951',4226'
Shale	4353	4572 TD	

(Attach separate sheets as necessary)

KAISER EXPLORATION AND MINING COMPANY
Well Operator

By: R. A. P

Date: October 26, 1982

Note: Regulation 2.02(i) provides as follows: "The term 'log' or 'well log' shall mean a systematic detailed geological record of all formations, including coal, encountered in the drilling of a well."

NOTICE: if the film image is less clear than this notice, it is due to the quality of the document being filmed

West Virginia Department of Mines
Office of Oil and Gas

Water Well Inspection Report

Date: [illegible] 1984

County: [illegible] District: Ripley Watershed: Straight Run

Property Owner: James Parsons Phone: 372-3046
Rt. 9 Box 67
Ripley WV 25271

Date problem was first detected: March - April 1984

Nature of Problem: First noticed odor - rotten eggs
June 22 1984 - Noticed white Silvers in water.
Gas in water well - Will burn at vent tube

Water source or supply type and specifications: Drilled well 1968
[illegible] Sand 406' Galvanized casing to top
of [illegible] sand (385') Dropped well submersible pump.

Is water quality data available from before water problems occurred. Yes
1970 Health Dept. Bacteria Count
1982 Health Dept. Bacteria Count

Has analysis been made after problem occurred. No
Will take sample & have analized.

What is the suspected cause of water problems: Kaiser gas well
drilled September 1982.

Listing of wells within 1000 feet of water well.

Remarks

District Oil and Gas Inspector

OGRA 010

Obverse
7-85

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AUG 28
DIVISION OF OIL & GAS
DEPARTMENT OF ENERGY

State of West Virginia
Department of Energy
Oil and Gas Division
Charleston 25311

FINAL INSPECTION REPORT
INSPECTORS COMPLIANCE REPORT
August 7, 1985

COMPANY Kaiser Exploration & Mining Co. PERMIT NO 035-1746-FRAC (3-29-85)

P. O. Box 8 FARM & WELL NO James Parsons, KEM-244

Ravenswood, West Virginia 26164 DIST. & COUNTY Ripley/Jackson

RULE	DESCRIPTION	IN COMPLIANCE YES	NO
23.06	Notification Prior to Starting Work	X	
25.04	Prepared before Drilling to Prevent Waste	X	
25.03	High-Pressure Drilling		
16.01	Required Permits at Wellsite	X	
15.03	Adequate Fresh Water Casing	X	
15.02	Adequate Coal Casing	X	
15.01	Adequate Production Casing	X	
15.04	Adequate Cement Strength	X	
15.05	Cement Type	X	
23.02	Maintained Access Roads	X	
25.01	Necessary Equipment to Prevent Waste	X	
23.04	Reclaimed Drilling Pits	X	
23.05	No Surface or Underground Pollution	X	
23.07	Requirements for Production & Gathering Pipelines	X	
16.01	Well Records on Site		
16.02	Well Records Filed		
7.05	Identification Markings	X	

I HAVE INSPECTED THE ABOVE CAPTIONED WELL AND RECOMMEND THAT IT BE RELEASED:

SIGNED [signature]

DATE 8-22-85

Your well record was received and reclamation requirements approved. In accordance with Chapter 22, Article 4, Section 2, the above well will remain under bond coverage for the life of the well.

[signature]

Director, Division of Oil & Gas

September 4, 1985
DATE

TMS/nw

PARTIAL + OIL

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Env. Health Servs.
Water Lab
NOV. 25 1985

WEST VIRGINIA STATE HEALTH DEPARTMENT
WATER ANALYSIS REPORT - INORGANICS
ENVIRONMENTAL HEALTH SERVICES LABORATORY

WATER SUPPLY	James Parson	COUNTY	Jackson
ADDRESS	Spencer Road, Rte. 1	LABORATORY NUMBER	852143
	Ripley, WV ZIP 25271	DATE OF ANALYSIS	DEC. 04 1985
POINT OF COLLECTION	outside tap	COLLECTED BY	Perry Merritt, San. IV
SOURCE:	Well (drilled)	DATE OF COLLECTION	November 25, 1985
FINISHED WATER	[ ]	RAW WATER	[X]
		TIME OF COLLECTION	

PRIMARY CONTAMINANTS (mg/l) & TURBIDITY [1]		SECONDARY STANDARDS (mg/l)	
Arsenic (0.05)	.	Chloride (250.0)	12.0
Barium (1.0)	.	Copper (1.0)	.
Cadmium (0.01)	.	Iron (0.3)	0.01
Chromium (0.05)	.	Manganese (0.05)	0.0
Lead (0.05)	.	Phenols (0.001)	.
Mercury (0.002)	.	Sulfate (250.0)	.
Fluoride (1.0 optimum)	3.32	TDS (500.0)	739.5
Turbidity (1.0 NTU)	.	Zinc (5.0)	.
Selenium (0.01)	.	Color (15.0 units)	.
Silver (0.05)	.	Odor (3.0 units) Not reportable	.
Nitrate (As N) (10)	< 0.04	Hydrogen Sulfide (0.05)	.
		Methylene Blue Active Substance (foaming agents) (0.5)	.

MISCELLANEOUS PARAMETERS (mg/l)

Alkalinity (PHTH) (As $CaCO_3$)	0.0	Cyanide (0.2)	.
Alkalinity (M.O.) (As $CaCO_3$)	416.0	Calcium	.
Hardness (A $CaCO_3$)	0.0	Magnesium	.
pH (units)	8.1	Sodium	240.0

REMARKS High sodium, TDS, JSR

CHEMISTS Rosencrance-Stratton-Hayes-Kee-Masin-Haynes-Coffman

Environmental Health Services Laboratory
151 11th Avenue, South Charleston, WV 25303
(304) 348-0197

[1] Maximum contaminant levels shown in parenthesis

PARTIAL & ODOR
EW-116

372-32#6

RECEIVED
Env. Health Serv...
Water Lab
SEP. 18 1984
Date

WEST VIRGINIA STATE HEALTH DEPARTMENT
WATER ANALYSIS REPORT - INORGANICS
ENVIRONMENTAL HEALTH SERVICES LABORATORY

WATER SUPPLY James Parsons
COUNTY Jackson
ADDRESS Rte. 4 Box 67
Ripley, WV ZIP 25271
LABORATORY NUMBER 84516
DATE OF ANALYSIS SEP 20 1984
POINT OF COLLECTION pump
COLLECTED BY Perry Merritt, Dir. Eng.
SOURCE: drilled well
DATE OF COLLECTION July 1, 1984
FINISHED WATER ☐ RAW WATER ☒
TIME OF COLLECTION

PRIMARY CONTAMINANTS (mg/l) & TURBIDITY [1]

Arsenic (0.05)	
Barium (1.0)	
Cadmium (0.01)	
Chromium (0.05)	
Lead (0.05)	
Mercury (0.002)	
Fluoride (1.0 optimum)	
Turbidity (1.0 NTU)	
Selenium (0.01)	
Silver (0.05)	
Nitrate (As N) (10)	

SECONDARY STANDARDS (mg/l)

Chloride (250.0)	
Copper (1.0)	
Iron (0.3)	
Manganese (0.05)	
Phenols (0.001)	
Sulfate (250.0)	
TDS (500.0)	
Zinc (5.0)	
Color (15.0 units)	
Odor (3.0 units)	Putrefying
Hydrogen Sulfide (0.05)	
Methylene Blue Active Substance (foaming agents) (0.5)	

MISCELLANEOUS PARAMETERS (mg/l)

Alkalinity (PHTH) (As $CaCO_3$)		Cyanide (0.2)	
Alkalinity (M.O.) (As $CaCO_3$)		Calcium	
Hardness (A $CaCO_3$)		Magnesium	
pH (units)		Sodium	

REMARKS

Microscopic examination reveals large glossy gelatinous masses indicative of a gel. There were numerous rod shaped particles present which were not readily distinguisha as a nuisance bacterial growth. They odor is of a putrefying description. JER

CHEMISTS Rosencrance-Stratton-Hayes-Kee-Masin-Haynes-Coffm

Environmental Health Services Laboratory
151 11th Avenue, South Charleston, WV 25303
(304) 348-0197

[1] Maximum contaminant levels shown in parenthesis

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WEST VIRGINIA STATE HEALTH DEPARTMENT
WATER ANALYSIS REPORT - INORGANICS
ENVIRONMENTAL HEALTH SERVICES LABORATORY

RECEIVED
Env. Health Serv.
Water Lab
AUG. 3 1 1984
Date

WATER SUPPLY	James Parsons	COUNTY	Jackson
ADDRESS	Rt 4 Box 67	LABORATORY NUMBER	841420
	Ripley, WV ZIP 25271	DATE OF ANALYSIS	SEP. 1 8 1984
POINT OF COLLECTION	Off Top of Well	COLLECTED BY	Mike Lewis, Eng
SOURCE:	Drilled Well	DATE OF COLLECTION	8-31-84
FINISHED WATER ☐	RAW WATER ☒	TIME OF COLLECTION	

PRIMARY CONTAMINANTS (mg/l) & TURBIDITY [1]		SECONDARY STANDARDS (mg/l)	
Arsenic (0.05)		Chloride (250.0)	59.0
Barium (1.0)		Copper (1.0)	
Cadmium (0.01)		Iron (0.3)	1.6
Chromium (0.05)		Manganese (0.05)	0.34
Lead (0.05)		Phenols (0.001)	
Mercury (0.002)		Sulfate (250.0)	
Fluoride (1.0 optimum)	3.48	TDS (500.0)	783.0
Turbidity (1.0 NTU)		Zinc (5.0)	
Selenium (0.01)		Color (15.0 units)	
Silver (0.05)		Odor (3.0 units)	
Nitrate (As N) (10)	< 0.04	Hydrogen Sulfide (0.05)	
		Methylene Blue Active Substance (foaming agents) (0.5)	

MISCELLANEOUS PARAMETERS (mg/l)

Alkalinity (PHTH) (As $CACO_3$)	0.0	Cyanide (0.2)	
Alkalinity (M.O.) (As $CACO_3$)	290.0	Calcium	
Hardness (A $CACO_3$)	10.0	Magnesium	
pH (units)	7.5	Sodium	295.0

REMARKS
1) High iron, manganese, fluoride and sodium
2) Quart jar residue – Characteristic of a sealant. DK
3) Small chlorine drinking jar residue – dark and light gelatinous material indicative of a gel. JK

Check sample on JR work be

CHEMISTS Rosencrance-Stratton-Hayes-Kee-Masin-Haynes-Coffm

Environmental Health Services Laboratory
151 11th Avenue, South Charleston, WV 25303
(304) 348-0197

1 Maximum contaminant levels shown in parenthesis

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WEST VIRGINIA STATE HEALTH DEPARTMENT
WATER ANALYSIS REPORT - INORGANICS
ENVIRONMENTAL HEALTH SERVICES LABORATORY

RECEIVED
Env. Health Servic.
Water Lab
Date SEP. 18 1984

WATER SUPPLY James Parsons

COUNTY Jackson

ADDRESS Rte. 4 Box 67
Ripley, WV ZIP

LABORATORY NUMBER 841517

DATE OF ANALYSIS SEP. 24 1984

POINT OF COLLECTION

COLLECTED BY Perry Merritt, Dir. Eng.

SOURCE: drilled well

DATE OF COLLECTION Sept. 17, 1984

FINISHED WATER [ ] RAW WATER [X]

TIME OF COLLECTION

PRIMARY CONTAMINANTS (mg/l) & TURBIDITY [1]		SECONDARY STANDARDS (mg/l)	
"Odor: Gas? Sulphur?"			
Arsenic (0.05)		Chloride (250.0)	11.0
Barium (1.0)		Copper (1.0)	
Cadmium (0.01)		Iron (0.3)	0.04
Chromium (0.05)		Manganese (0.05)	0.00
Lead (0.05)		Phenols (0.001)	
Mercury (0.002)		Sulfate (250.0)	
Fluoride (1.0 optimum)	3.76	TDS (500.0)	435.0
Turbidity (1.0 NTU)		Zinc (5.0)	
Selenium (0.01)		Color (15.0 units)	HYDROCARBON ODOR
Silver (0.05)		Odor (3.0 units)	
Nitrate (As N) (10)	0.04	Hydrogen Sulfide (0.05)	0.03
		Methylene Blue Active Substance (foaming agents) (0.5)	

MISCELLANEOUS PARAMETERS (mg/l)

Alkalinity (PHTH) (As $CACO_3$)	0.0	Cyanide (0.2)	
Alkalinity (M.O.) (As $CACO_3$)	407.0	Calcium	
Hardness (A $CACO_3$)	0.0	Magnesium	
pH (units)	8.1	Sodium	175.0

REMARKS Hydrocarbon odor indicative of gas.
High alkalinity, high sodium. JKL

CHEMISTS Rosencrance-Stratton-Hayes-Kee-Masin-Haynes-Coffm

Environmental Health Services Laboratory
151 11th Avenue, South Charleston, WV 25303
(304) 348-0197

[1] Maximum contaminant levels shown in parenthesis

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WEST VIRGINIA STATE HEALTH DEPARTMENT

WATER ANALYSIS REPORT - INORGANICS

ENVIRONMENTAL HEALTH SERVICES LABORATORY

RECEIVED
Env. Health Service
Water Lab
NOV. 26 1984

WATER SUPPLY James Parson

ADDRESS Ripley, WV

ZIP

POINT OF COLLECTION of spigot

SOURCE: Well

FINISHED WATER [ ] RAW WATER [X]

COUNTY Jackson

LABORATORY NUMBER 841842

DATE OF ANALYSIS NOV. 30 1984

COLLECTED BY Perry Merritt, Dir. Env. Hea

DATE OF COLLECTION November, 23, 1984

TIME OF COLLECTION

PRIMARY CONTAMINANTS (mg/l) & TURBIDITY [1]

Arsenic (0.05)	
Barium (1.0)	
Cadmium (0.01)	
Chromium (0.05)	
Lead (0.05)	
Mercury (0.002)	
Fluoride (1.0 optimum)	4.12
Turbidity (1.0 NTU)	
Selenium (0.01)	
Silver (0.05)	
Nitrate (As N) (10)	< 0.04

SECONDARY STANDARDS (mg/l)

Chloride (250.0)	14.0
Copper (1.0)	
Iron (0.3)	0.00
Manganese (0.05)	0.00
Phenols (0.001)	
Sulfate (250.0)	
TDS (500.0)	478.5
Zinc (5.0)	
Color (15.0 units)	
Odor (3.0 units)	
Hydrogen Sulfide (0.05)	
Methylene Blue Active Substance (foaming agents) (0.5)	

MISCELLANEOUS PARAMETERS (mg/l)

Alkalinity (PHTH) (As $CaCO_3$)	12.0	Cyanide (0.2)	
Alkalinity (M.O.) (As $CaCO_3$)	411.0	Calcium	
Hardness (A $CaCO_3$)	24.0	Magnesium	
pH (units)	8.3	Sodium	103.0

REMARKS High sodium JEH

CHEMISTS Rosencrance-Stratton-Hayes-Kee-Masin-Haynes-Coffm

Environmental Health Services Laboratory
151 11th Avenue, South Charleston, WV 25303
(304) 348-0197

[1] Maximum contaminant levels shown in parenthesis

NOV 13 1984 file

John D. Rockefeller IV
Governor

L. Clark Hansbarger, M.D.
Director

State of West Virginia

DEPARTMENT OF HEALTH
CHARLESTON 25305

November 8, 1984

Perry R. Merritt, Sanitarian IV
Jackson County Health Department
Environmental Health Section
Ripley, West Virginia 25271

Dear Mr. Merritt:

Your letter of November 5, 1984 with reference to the three samples taken from the water supply of Mr. James Parsons, Ripley, West Virginia has been received.

An evaluation of the three reports (copies enclosed) would indicate that this water supply is contaminated from a chemical point of view which may have resulted from oil and gas drilling operations in the vicinity of the Parsons water supply.

It is not unusual to find high alkalinity, high fluoride, high sodium and high total dissolved solids in the underground water in that particular area of Jackson County, but is would be unusual to find the gelatinous material which we isolated unless it had been used by the drilling industry. This laboratory has identified the presence of hydrocarbons in [illegible] of the samples which is indicative of petroleum type products.

The laboratory is not familiar with the chemical characteristics of this well previous to the samples analyzed in July, August and September of 1984.

At this time, there is no home type treatment that would remove the objectional materials that have been found in this water supply. Any attempt to filter the water would be futile since the gelationous material would clog the filter in a very short period of time. Such things as sodium, fluoride, high alkalinities and extraneous materials are not easily removed in home type supplies. A new source of water is suggested for the Parsons residence.

Very truly yours,

James E. Rosencrance

James E. Rosencrance, M.S., Chief
Environmental Health Services Lab

cc: Don Kuntz, Env. Eng. Div
Mike Lewis, Dept. of Mines
Oil & Gas

Enclosures: 3

Arch A. Moore, Jr.
Governor

L. Clark Hansbarger, M.D.
Director

State of West Virginia

DEPARTMENT OF HEALTH
CHARLESTON 25305

April 3, 1985

Mr. James Parsons
Route #4, Box 67
Ripley, West Virginia 25271

Dear Mr. Parsons:

This letter will follow up my telephone conversation with Mrs. Parsons on this date relative to the problem with water quality at your residence.

Enclosed are copies of our laboratory reports 841516, 841517, 841420 and 841842 which were completed by the Environmental Health Services Laboratory in July, August, September and November of 1984. These samples showed various chemical characteristics which indicated pollutants were entering your water supply and causing conditions which made the water unsatisfactory for household use. It is our understanding that a gas well was fractured within 600 feet of your water well and may be involved with the pollutants found in the water.

There are no funds or programs available within the State of West Virginia which would financially assist you in correcting the pollution problem with your well water. The superfund program administered by the Environmental Protection Agency is restricted on any assistance which they may provide relative to oil and gas drilling operations affecting the water quality of your well. However, you may desire to pursue this matter on your own in an effort to have the gas drilling operators responsible for the contamination to develop you a new source of water. You may use the laboratory reports as evidence of our findings at the time the water samples were submitted to the lab, and our advice at that time that the water was unsatisfactory for household use.

Your recent information has indicated that after cleaning the well and pulling the pump for servicing, the water quality has improved but ~~it~~ is not used for drinking and cooking purposes.

If we can be of any further service to you in regards to this matter please contact us.

Very truly yours,

James E. Rosencrance

James E. Rosencrance, M.S., Chief
Environmental Health Services Lab

cc: Perry Merritt, R.S.
Jackson County Health Dept.

IN THE CIRCUIT COURT OF JACKSON COUNTY, WEST VIRGINIA

RECORDED
FEB 3 2 PM '86
T.A. BARNETTE
JACKSON COUNTY
CIRCUIT CLERK

JAMES O. PARSONS, and
N. RUTH PARSONS, his wife,

Plaintiffs,

v. CIVIL ACTION NO. 86-C-31

KAISER EXPLORATION & MINING
COMPANY,

Defendants.

C O M P L A I N T

Comes now the plaintiffs, by their counsel, Robert Q. Sayre, Jr., and Goodwin & Goodwin, and file this Complaint which states as follows:

I

1. James O. Parsons, and N. Ruth Parsons, his wife, are the owners of the surface and minerals of an 85 acre tract of land situate in Ripley District of Jackson County, West Virginia, upon which they reside.

2. Kaiser Exploration and Mining Company (hereafter referred to as "Kaiser"), is a corporation organized pursuant to the laws of the State of Delaware; has its principal place of business in Ravenswood, Jackson County, in the State of West Virginia; and is authorized to do business in the State of West Virginia.

3. In the fall of 1967, the plaintiffs caused a water well to be drilled on said 85 acre tract to furnish water for drinking, cooking, and other domestic uses. Said water well was drilled

approximately 400 feet deep and was lined with steel casing, at great personal expense to the plaintiffs.

4. At the time the water well was drilled, and for several years thereafter, the water was clean, safe and good tasting, clear and free of other problems up to the time in which the defendants oil and gas operations began.

5. On the 25th day of August, 1981, plaintiffs, James O. Parsons and N. Ruth Parsons, his wife, as lessors, executed a lease agreement with the defendant, Kaiser, as lessee, which granted the defendant the right to produce oil and gas on said 85 acre tract for three years or as long thereafter as production continues, such lease agreement to be found recorded in the Office of the County Clerk of Jackson County in Lease Book 164, at page 287.

6. In or about September of 1982, the defendant drilled an oil and gas production well on said 85 acre tract, and sometime thereafter fractured said well.

7. Said well was assigned the name of "KEM 244 Parsons".

8. The well drilled by the defendant around September 1982 on the said 85 acre tract was within 1000 feet of said water well of the plaintiffs.

9. Shortly after the drilling of the aforesaid oil and gas well, the plaintiffs began to experience considerable problems with their water supply, and the same has become contaminated and unfit for household or other uses.

10. Said contamination was caused by the defendants activities in drilling a well within 1000 feet of the plaintiffs water well, in fracturing said well, or in otherwise operating said well.

11. The plaintiffs have been advised by the Department of Health that no treatment or process will solve their problem of contamination and that a new water source will have to be found to safely supply water to the plaintiffs home.

12. As a direct result of defendants aforesaid oil and gas exploration and activities, plaintiffs have had to go through considerable inconvenience to carry water to their home for cooking and drinking, have had their normal lifestyles interrupted, and have suffered humiliation in being required to bathe in contaminated water and have worried about the possible side effects to their health.

13. Plaintiffs' water well is permanently damaged due to the drilling, fracturing, and operation of the aforesaid oil and gas well by the defendant within 1000 feet of their water well and by virtue of West Virginia Code § 22-4-19 defendants are liable to plaintiffs for damages the plaintiffs have incurred as a result of the aforesaid activities.

14. Plaintiffs' water well is permanently damaged due to the negligent drilling, fracturing, and operation of the aforesaid oil and gas well by the defendant within 1000 feet of their water well.

15. Despite repeated requests, defendants have failed to ameliorate such damage or to assist plaintiffs in locating a new source of safe water.

16. Besides permanent damages to the water well, plaintiffs have suffered great expense and inconvenience in obtaining water for drinking and cooking by carrying same, and will have locate, drill and pump a new and deeper well, if possible, or have water pumped from an external source. Plaintiffs has also suffered damage to their property

as a result of it diminution in value because of the lack of a potable water supply.

WHEREFORE, plaintiff prays that they should be awarded $50,000.00 in compensatory damages for property damage to plaintiffs water well, including the costs in time and money for the inconvenience and loss of use of their water well, for obtaining water while a new source of usable water is located, for locating and producing a clean and reliable new source of water, and such other monies as may be necessary to fully compensate the plaintiffs for the damages they have incurred as a direct result of the defendant's actions as described herein. Plaintiff prays for any other such relief which may be appropriate to serve the interests of justice.

Plaintiff demands a trial by jury.

JAMES O. PARSONS and N. RUTH PARSONS

By Counsel

ROBERT Q. SAYRE, JR.
GOODWIN & GOODWIN
1500 One Valley Square
Charleston, West Virginia 25301

IN THE CIRCUIT COURT OF JACKSON COUNTY, WEST VIRGINIA

JAMES O. PARSONS, and
N. RUTH PARSONS, his wife,

Plaintiffs,

v.

CIVIL ACTION NO. 86-C-31

KAISER EXPLORATION &
MINING COMPANY,

Defendant.

A N S W E R

Defendant Kaiser Exploration and Mining Company ("Kaiser") for answer to the Complaint herein, says as follows:

FIRST DEFENSE

Plaintiffs' Complaint is barred by the two year statute of limitations applicable to claims for property damage or personal injuries pursuant to W. Va. Code §55-2-12(a) and (b).

SECOND DEFENSE

1. Kaiser is without information or knowledge sufficient to form a belief regarding the truth of the allegations contained within Paragraph Nos. 1, 3 and 4 of the Complaint, and therefore denies same.

2. Kaiser admits the allegations contained in Paragraph No. 2 of the Complaint.

3. Kaiser admits the allegations contained in Paragraph Nos. 5, 6, 7 and 8 of the Complaint.

4. Kaiser is without knowledge or information sufficient to form a belief regarding the truth of the allegations contained in Paragraph No. 9 of the Complaint and therefore denies same.

5. Kaiser denies each and every allegation contained in Paragraph No. 10 of the Complaint.

6. Kaiser is without knowledge or information sufficient to form a belief regarding the truth of the allegations contained in Paragraph No. 11 of the Complaint, and therefore denies same.

7. Kaiser denies each and every allegation contained within Paragraph Nos. 12, 13 and 14 of the Complaint.

8. With respect to Paragraph No. 15 of the Complaint, Kaiser admits that the plaintiffs have made certain demands of the defendant, but Kaiser denies each and every allegation of the paragraph to the extent that it implies or infers that the defendant is in any way liable to the plaintiffs, or that the defendant has or had any duty to ameliorate any alleged damage or to assist plaintiffs in locating a new source of safe water.

9. With respect to Paragraph No. 16 of the Complaint, Kaiser is without knowledge or information sufficient to form a belief regarding whether the plaintiffs have suffered great expense and inconvenience or suffered damage as alleged in said paragraph, and in any event, denies said paragraph to the extent that it implies and infers that any such alleged damages or injuries are in any way the liability or fault of Kaiser.

THIRD DEFENSE

Kaiser denies the applicability of W. Va. Code §22-4-19, and further denies that it is liable in any manner to the plaintiffs by operation of statute, common law, or otherwise.

FOURTH DEFENSE

The Complaint fails to state a claim upon which relief may be granted.

WHEREFORE, the defendant Kaiser Exploration and Mining Company having answered the Complaint and denying all liability, demands a judgment be entered in behalf of the defendant Kaiser Exploration and Mining Company, and that it be awarded all costs and attorneys' fees expended in defense of this action, and such other and further relief as the Court may deem appropriate.

KAISER EXPLORATION AND MINING COMPANY

By Counsel

ROBINSON & McELWEE

Timothy M Miller

Timothy M. Miller

E. Glenn Robinson

E. Glenn Robinson

600 United Center
Post Office Box 1791
Charleston, West Virginia 25326
(304) 344-5800

CERTIFICATE OF SERVICE

I, Timothy M. Miller, counsel for the defendant, hereby certify that on this 23rd day of January, 1987, I served a true copy of the foregoing ANSWER upon plaintiffs' counsel of record, by hand delivery or mailing of a true copy thereof addressed to Robert Q. Sayre, Jr., Esquire, Goodwin & Goodwin, 1500 One Valley Square, Charleston, West Virginia 25301.

Timothy M. Miller

Timothy M. Miller

Research and Development Laboratory
NOWSCO Well Service Ltd.
6920-36th STREET S.E. CALGARY, CANADA T2C 2G4 TELEPHONE (403) 279-8841

March 11, 1985
NRD - 85-202

K E M G A S

Re:
Kem 244 Parsons
Contamination Analysis

Nowsco Representative

Orville Atchison

Research and Development Laboratory
NOWSCO Well Service Ltd.
6920-36th STREET S.E. CALGARY, CANADA T2C 2G4 TELEPHONE (403) 279-8841

LABORATORY REPORT

Report No.: NRD - 85-202
Date: March 11, 1985

COMPANY: Kem Gas

WELL NAME: Kem 244 Parsons

LOCATION: Jackson County, West Virginia

FIELD: Ripley

Lab Sample No.	Sample Description
N-5455	water from well 1000 feet away from fraced well

The above samples were analyzed to determine if any contamination from frac water is present.

Composition

The above fluid sample was spun out using a high speed centrifuge and was found to have the following composition.

oil	nil
water	100%
sediment	nil

Water Analysis

The water portion of the above sample was subjected to a full water analysis. The results of this analysis are given in Attachment No.1. These results are indicative of very fresh water.

Bacteria Analysis

The above water sample was tested for coleform and sulfate reducing bacteria. It is reasoned that gel residue, if present, would provide nutrients to the bacteria. The results of the three day test were negative in both cases.

continued . . .

Surface Tension Measurements

Trace amounts of surfactants in water will significantly lower the surface tension of the water. The measured surface tension of the above samples was 65.7 dynes/cm which is typical of fresh water with no surfactants at room temperature.

Discussion

From the above analysis, no contamination from frac water is evident in the sample from the water well.

Please contact us should you have any questions regarding this report.

Yours truly

NOWSCO WELL SERVICE LTD.

RKMeyer

R. K. Meyer, B.Sc.
Lab Supervisor
Stimulation Technical Services

RKM/llh
att.

ATTACHMENT No. 1

WATER ANALYSIS

Sample No.: N- 5455

OBSERVED pH: 8.33 @ 22C

ION	mg/L	MG%	meq/L	ION	mg/L	MG%	meq/L
Na	251	23.2	11	Cl	350	32.3	10
K	1	0.1	0	SO4	0	0.0	0
Ca	0	0.0	0	HCO3	471	43.5	8
Mg	0	0.0	0	CO3	10	0.9	0
Fe	0	0.0	0	OH	0	0.0	0
Mn	0	0.0	0				
	252	23.3	11		831	76.7	18

SPECIFIC GRAVITY

1.0020 =	2845
@15.6C	mg/L NaCl

REFRACTIVE INDEX

1.3331 =	582
@ 25C	mg/L NaCl

RESISTIVITY, ohm/m

% 10.8 =	525
@ 20C	mg/L NaCl

H2S PRESENT: NO

TOTAL HARDNESS: 1
(As mg/L CaCO3)

TOTAL ALKALINITY: 402
(As mg/L CaCO3)

CALCULATED DISSOLVED SOLIDS: 1083 mg/L

BCM Laboratory Division
Appalachian Group
325 Thirteenth Street, Dunbar, W. Va. 25064
304: 766-6283

CLIENT

KAISER EXPLORATION & MINING CO 07-740455
P.O. BOX 8
RAVENSWOOD, WV 26164
ATTN: JOHN WHITE 11/21/84

FINAL REPORT

This is the final report for the samples shown below. If you have questions concerning this report please call 304-766-6283.

BCM NUMBER	B408760
CLIENT SAMPLE ID	JAMES PARS ONS
DATE SAMPLED	11/15/84
DATE RECEIVED	11/15/84
ALUMINUM MG/L	<0.2
ALKALINITY (AS CaCO3) MG/L	470
CALCIUM MG/L	0.64
CHLORIDE MG/L	10
SOLIDS,DISSOLVED (70300) MG/L	560
IRON MG/L	<0.02
POTASSIUM MG/L	0.9
SURFACTANTS (MBAS) MG/L	0.02
MAGNESIUM MG/L	0.15
MANGANESE MG/L	<0.01

BCM Laboratory Division
Appalachian Group
325 Thirteenth Street, Dunbar, W. Va. 25064
304: 766-6283

CLIENT

KAISER EXPLORATION & MINING CO 07-740455

BCM NUMBER	D408760
SODIUM MG/L	100
NITROGEN, NITRATE MG/L	0.1
TURBIDITY NTU	1.1
PH STD UNIT	8.9
SULFATE MG/L	41
TOTAL COLIFORM COL/100ML	<1

END OF REPORT

OGRA-50-679

EPA, API MEETING ON EPA
PRODUCTION WASTE STUDY

AUGUST 10, 1987

NAME	ORGANIZATION	Telephone
Tom Roche	EXXON	(713)-656-5651
Jan Fisher	ARCO	202-4576260
Meg Collins	Union Pacific Resources	202-861-8820
Bill Freeman	Shell oil Co.	713-241-1455
Joe Carra	EPA/OSW	202-382-7919
Mike Heffner	STANDARD (HOUSTON)	713-552-8641
Arden Ahnell	Standard (Cleveland)	216-581-5674
Dan Chadwick	EPA/OSW	202-475-7370
Lyn Herdt	Std. Oil (DC)	785-4888
Jim Collins	ARCO OIL & GAS	214-880-4818
Cliff Rothenstein	EPA/OSW	202-382-2791
Bob Hall	EPA/OSW	202-475-7415
Nina Springer	Exxon Production Research Co.	(713) 965-4[illegible]
Joel Robins	Amoco Prod. Co.	(713) 556-2444
Michael Alford	VERSAR	(703) 750-3000
Dan Derkics	US EPA, OSW	(202) 382-3608
Carla Greathouse	VERSAR	(703) 750-3000
Mike Fitzpatrick	EPA/OSW	(202) 382-7597
Harold Yates	Exxon	713-656-3452
Frank A. Smith	EPA/OSW	382-2791
Marc Himmelstein	API	682 8450

API Comments on
Preliminary Draft Report to Congress
Oil, Gas and Geothermal Wastes

GENERAL COMMENTS & QUESTIONS

- API would welcome the opportunity to answer questions on its recently completed study or discuss its content in any forum of EPA's choice.

- How much additional material (risk, economics, damages) will be included in the Draft Report? When will it be available?

- Has EPA management responsible for administration of injection wells (Safe Drinking Water Act/UIC) and Clean Water Act (NPDES) discharges been involved in assessing the adequacy of their programs? Does EPA believe these programs are covered by RCRA? API's understanding of the legal framework is attached.

- Will the proposed TCLP test be used in the Draft Report in view of its problems and reevaluation (May 18, 1987 Federal Register)? When will the decision be made?

- Is there any opportunity for API to comment on the Draft Report to Congress prior to the planned February-March, 1988, public meetings? Will EPA accept API written comment on the Draft Report?

- How will EPA use the analyses of waste contained in "constituents and comparisons to hazardous waste regulatory limits" in the Draft Report? How do they compare to API analyses exchanged with EPA?

- Will Chapter 7 information on State and Federal Regulations information be incorporated into discussions of industry practices, damage cases and health and environmental impacts?

■ API continues to disagree with EPA that waters used in additional recovery projects are wastes under RCRA. API believes they are a necessary part of the oil recovery process and are therefore excluded from the definition of solid waste. Will EPA provide any separation of impacts for additional recovery waters in its analysis?

■ API disagrees with the Draft Report "PFS" concept and believes the exemption is improperly redefined in the report. Has EPA provided prior guidance supporting this concept and are EPA regions using this interpretation?

■ What use will the Draft Report make of damage cases from non-waste issues such as oil spills, Clean Water Act discharges, etc?

■ Is there additional documentation regarding damage cases and information contained in API and state comments that would be useful to EPA?

■ How will enforcement issues be addressed in determining the need for additional regulations?

■ How will the LLM model and input parameters be qualified or validated to ensure its results are matched with actual field observation and damage cases? Will the qualitative assessment of risk to environmental resources be verified against field observations and damage cases?

■ Will LLM input parameters reflect API Column test data and other scientific studies on reduced mobility and attenuation found in reserve pits?

■ Have the methodology and input parameters for modeling releases from injection wells been revised from the Interim Report based on API comments?

- How will the significance of the qualitative determination of risk to natural resources be assessed, and what methodology will be used to determine the acceptability of these estimated risks?

- Why does the Draft Report contain non-hazardous waste management scenarios in the economic impact section? Why does the economic impact analysis assume for its non-hazardous cases that Clean Water Act discharges (not regulated by RCRA) will not be allowed?

- What costs are included for industry's 168,000 injection wells? Does the cost model recognize that regulation of these wells as hazardous waste wells would require redrilling or modifying non Class I producing and injection wells within "areas of review"?

- How will the economic analysis relate the 21 well models to industry's 842,000 producing and 168,000 injection wells?

Legal Framework for
EPA Study of Oil and
Gas Waste under
<u>Section 8002(m) of RCRA</u>

■ Section 3001(a) (2) (A) exempts drilling fluids, produced waters and other oil and gas associated wastes from regulation as hazardous waste under Subtitle C of RCRA until the Section 8002(m) study is completed, EPA determines such regulation is necessary and any proposed regulations are approved by Act of Congress.

-- even if EPA determines that the overall exemption should be removed, it is only authorized under Subtitle C RCRA to regulate "hazardous Wastes." Consequently, only those oil and gas materials which are hazardous <u>wastes</u> can be regulated under Subtitle C

  -- under Section 1004(5) of RCRA a "hazardous waste" waste must be a "solid waste"

  -- Section 1004(27) defines "solid waste" to mean only garbage, refuse, sludge or "other discarded material"

-- produced water used for enhanced oil recovery operations is an integral part of the production process - it is not "discarded" and therefore it is not a "solid waste" subject to RCRA regulation

-- This position was upheld by the United States Court of Appeals for the D. C. Circuit the week of July 27, 1987 in <u>American Mining Congress v. EPA</u> which invalidated EPA's attempt to regulate secondary materials reused with an industry's ongoing production process as a hazardous waste under subtitle C. The court held that since such secondary materials resulting from primary processing were not "discharged" they were not "solid

waste" and therefore not covered by RCRA. This case is directly on point with respect to produced water for enhanced oil recovery.

-- Since produced water used for enhanced oil recovery is not subject to regulation as a "solid waste" under RCRA, it should be excluded from the Section 8000(m) study

- Section 1003 of RCRA provides that its objective is to protect human health and environment from activities involving <u>solid waste activities</u> - it does not cover the regulation of activities not involving not-solid wastes practices or issues including the production of crude oil or the handling of products etc. covered by such other statutes such as OSHA

- Section 1006 or RCRA and 40 CPR Section 261.4(a) (2) exempt discharges subject to the NPDES program under the Clean Water Act from regulation as a solid waste under RCRA. Consequently, such discharges should not be included in the Section 8002(m) study.

Chapter I-Introduction

- API feels redefining the scope of the exemption at this time is unwarranted. Any modifications of the exemption such as the proposed narrowing (PFS concept) would constitute a regulatory determination with immediate implications for industry. See Chapter II comments for further discussion.

- The description of damage cases should recognize a number of cases are based on pending court cases where facts have yet to be established. And, in other cases, the scientific evidence used was provided by private citizens or attorneys alleging damage and seeking compensation.

- It is noted that 249 damage cases were referenced versus the 228 that were included in the Interim Report. If these additional cases are used for background or risk assessment information, API would appreciate the opportunity to review and comment upon the additional cases.

- API agrees with the logic that the damage cases because they are almost all violations of current state and federal regulations cannot be used to demonstrate adequacy of state of federal enforcement efforts. Such an investigation would require significant additional effort to gather necessary data. However, it is felt that when the cases are grouped into "damage" categories that they are useful in demonstrating the extent of the current regulatory framework present for oil and gas wastes. See comments on Chapter IV.

- As described, the risk assessment modeling section is intended to be a screening procedure to indicate potential

concerns with management of E&P wastes. If the screening model results indicate potential problem areas, what are EPA's plans to more rigorously determine the actual levels of risk to human health and the environment?

- API comments on Chapter V on risk assessment address our concerns that any risks predicted must be correlated or validated against real world occurrences. Also, as presented in API's comments on the Interim Report, API has concerns with the model used and quality of selected input data.

- While useful information may be gathered in the approach proposed for the "Review of State Programs" Chapter, it should be recognized that state and federal programs have evolved based upon reacting to problems versus looking for inconsistencies and gaps in coverage between regulatory bodies. Also, because the purpose of this study as mandated by Congress is to determine if additional regulations are warranted, it would be useful to review the findings of this chapter against the damage cases.

- The "alternative" nonhazardous waste economic case described as "uniform nationwide use of the most up-to-date and effective controls now being applied by any of the states" in effect applies the lowest common denominator approach to regulation and does not account for wide variations in geographical and environmental situations. It would require many unnecessary expenditures that would not result in incremental environmental protection.

CHAPTER II - "DESCRIPTION OF INDUSTRY"

- A summary of API comments on this Chapter follows:

  -- EPA's Chapter II reflects a fairly accurate assessment of industry operations.

  -- The API data base has been reviewed by academia (Dr. Gordon Otto, University of Houston) and provides reasonably accurate volumetric estimates.

  -- EPA has introduced the PFS concept which severely limits the extent of the Congressional exemption. API believes redefining the exemption at this time is unwarranted. This issue deserves further review and consideration by the agency.

- The report makes some incorrect statements in this chapter about exploration and production activities. The following corrections should be made:

  -- Natural gas is not used as a gaseous drilling fluid. API's previous comments addressed the dangerous nature of such an operation.

  -- Oil-based drilling fluids account for not more than 5% (1986 API Survey) of the total volume of drilling fluids nationwide.

  -- Crude oil treated with chemicals or skimmed from surface impoundments are recycled, not discarded. similarly, oil stained soil and gravel are properly disposed of, not discarded.

  -- The disposal of the various wastes cited on page 7 (conclusions) are appropriately regulated by states.

- A description of industry wastes comparing API and EPA field sampling and analysis results should be included discussing the constituents of concern present in the waste and the concentrations at which they occur.

- The report makes the determination that "all produced water is solid waste, regardless of its end use or disposal method." The act defines solid waste as that which is discarded.

  -- Nearly 70% of all produced or makeup waters utilized in EOR projects is returned to an oil bearing formation and consequently stays in a recycling mode. This produced water is not discarded.

  -- Another 5% of all produced water is designated as "beneficial use" as (as defined under the Clean Water Act) and is used for watering stock and vegetation and is, therefore, not discarded. This is particularly relevant to the Rocky Mountain states.

- In the context of commingling waste streams in the field, EPA's UIC regulations address the integral nature of gas plant (process) waste waters and other waste streams such as steam generator scrubber water. These streams are allowed to be commingled prior to injection under the Class II UIC program providing they are not classified as hazardous at the time of injection.

- The report attempts to define the scope of the current exemption under § 3001(a) (2) (A) in Chapter II.B.2 "Definition of Exempted Wastes". The attempted definition is clearly erroneous and fails to follow the statutory language or the legislature history of the exemption. Attached are detailed comments on the proposed scope of the exemption.

Comments to Draft of
Draft RTC - Chapter II.B.2,
"Definition of Exempted Wastes"

In attempting to define the scope of wastes currently exempt under §3001(a)(2)(A), EPA erroneously relies on the following three "assumptions":

- that "drilling fluids and produced waters," as well as "other wastes" must be "intrinsically derived from primary field operations" to be covered by the exemption,
- that only wastes injected into the ground or extracted from the ground are covered by the exemption, and
- all produced water, regardless of whether it is injected for disposal or enhanced recovery purposes, are wastes and therefore not covered by the exemption.

None of those "assumptions" are supported by §3001(a)(2)(A) or its legislative history.[1]

The express language of §3001(a)(2)(A) on its face broadly defines the exemption to cover "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas." The legislative history is limited but is best illustrated by the Conference Report submitted by the House of Representatives on the 1980 RCRA Amendments.[2] However, the Conference Report only attempts to define the scope of "other wastes" which it indicated had to be "intrinsically derived from primary field operations." The Conference Report noted that "intrinsically derived from primary field operations" was intended to distinguish exploration, development and production from transportation and manufacturing.

In its "assumptions" EPA erroneously concluded that "drilling fluids and produced waters" was also subject to the"intrinsically derived from primary field operations" qualification for "other wastes." This is not supported by the language of §3001(a)(2)(A) or the legislative history. EPA also erroneously concluded that the only wastes covered by the exemption are those extracted from the ground or injected into the ground - this conclusion again is

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[1] The third assumption is not addressed specifically here but is subject to separate comments.

[2] H. Conf. Rep. No. 96-1444, 96th Congress, reprinted in 1980 U.S. Code Cong. + Adm. News 5019. A copy of the most relevant provisions are attached.

not supported by the language of the statute or the legislative history.

Compounding these erroneous conclusions, EPA attempts to limit the scope of the exemption to the "Primary Field Site" - a term not defined or discussed in the statute or the legislative history. The attempt is to artificially restrict the scope of the exemption to the narrowest production entity, i.e., operations upstream and including a tank battery. The Agency then concludes that any waste - including <u>produced</u> <u>water</u> - extracted outside of the Primary Field Site is not covered by the exemption.

One glaring conflict with the "Primary Field Site" concept is it restricts the exemption for produced waters to those separated or otherwise removed at or near the wellhead. It ignores the fact that a significant amount of water produced with gas may be removed at centralized dehydration facilities or gas plants which, because of economic, geographic or even environmental concerns, may not be located on the "Primary Field Site," as defined by EPA. This is in clear conflict with §3001(a)(2)(B) and the legislative history which places no geographic limitation of the exemption for produced water. Even with "other wastes," the "Primary Field Site" limitation is overly restrictive. The Agency failed to recognize that Congress' use of the term "intrinsically derived from primary field operations" (presumably from where the "Primary Field Site" derives) was only intended to distinguish clearly "upstream" <u>functions</u> involving exploration/development/production from "downstream" functions, i.e., transportation to market or manufacturing (e.g., petroleum refining). It clearly was not intended to <u>geographically</u> restrict the scope of the exemption.

The "assumption" that only wastes extracted from the ground or injected into the ground is covered by the exemption is also not supported by §3001(a)(2)(A) or the legislative history. It also fails to recognize that many important materials crucial to production operations may not fit in those categories, i.e., treatment chemicals, corrosion inhibitors, etc. This also results in the erroneous specific conclusions that spent iron sponge, filters, etc. are not covered by the exemption.

Other conclusions reached by the Agency which are not supported by §3001(a)(2)(A) or the legislative history are as follows:

- the "uniquely associated" requirement - particularly applied to the possible relatively minor mixture or commingling of non-exempt wastes

- the implicit assumption that all gas plants wastes are not covered by the exemption because they are not located on the Primary Field Site or are incorrectly viewed as resulting from a manufacturing operation

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The term 'other wastes associated' is specifically included to designate waste material <u>intrinsically derived from the primary field operations</u> associated with the exploration, development, or production of crude oil, natural gas, or geothermal energy. It would cover such substances as: Hydrocarbon bearing soil in and around the related facilities; drill cuttings; materials (such as hydrocarbon, water, sand, and emulsion) produced from a well in conjunction with crude oil, natural gas, or geothermal energy; and the accumulated material (such as hydrocarbon, water, sand, and emulsion) from production separators, fluid treating vessels, storage vessels and production impoundments.

The phrase 'intrinsically derived from the primary field operations . . .' is intended to differentiate exploration, development, and production operations from transportation (from the point of custody transfer or of production separation and dehydration) and manufacturing operations.

ATTACHMENT

CHAPTER III - CURRENT AND ALTERNATIVE
WASTE MANAGEMENT PRACTICES

- The major issues in this Chapter are as follows:

  -- The report indicates seepage in drilling pits is part of the pit dewatering phase during pit closure.

  -- Landspreading is not characterized correctly for onsite pit closure operations.

  -- Drilling fluids are not necessarily injected down surface pipe because they contain objectionable levels of contaminants.

  -- State UIC programs may be different, but there is a minimum standard requirement by EPA before primacy is delegated to the states.

  -- There are many incentives including economic ones for operators to assure saltwater disposal wells have mechanical integrity.

- While the present draft reflects significant improvements over the Interim Report, EPA's contractor still uses outdated information in certain sections of the Chapter. For example, Table 2 still lists galena (PbS) and sodium chromate as additives used in drilling mud, even though they are no longer used in U.S. drilling operations. Further, the 1978 estimated diesel volume used in drilling is too high and should be adjusted for present usage. The quotes on page 34 about state program requirements for identifying USDW's are also outdated and not completely correct. For example, Mississippi requires surface casing on wells to be set at depths based upon the total depth of the well being drilled, not TDS values.

- The report inaccurately indicates seepage in drilling pits is part of the pit closure techniques on page 13. If seepage occurs in a drilling pit, it is not design. Seepage is kept to a minimum in all drilling pits due to the self sealing properties of drilling muds. Column leach studies (furnished to EPA by API) substantiate that filter cakes with permeabilities of 1×10^{-6} or lower cm/sec can be created in drilling pits. Seepage of fluids from drilling pits is not part of a pit closure technique nor do we believe it is a significant contributor to USDW contamination. The fact is that 37% of drilling pits have artificial liners installed where highly permeable soils exist over shallow groundwater or where bentonite is not added to the drilling fluid.

- The report characterizes landspreading incorrectly. Land spreading is not, in most cases, a supplemental step taken to dispose of excess muds squeezed out during burial of pit solids in a pit closure operation. This technique requires the operator to remove the drilling solids form the pit and spread those solids on the ground, provided that metal, salts and hydrocarbon concentrations comply with state constituent criteria. As incorrectly described by the report, landspreading is not an after-thought in a pit closure operation and is not normally done without a planned design.

- In the discussion of Alaskan North Slope drilling wastes, the report refers to "road watering" as the only disposal alternative to decanting reserve pit fluids to the tundra. It should be noted that annular injection and conventional Class II disposal are also current practices.

- The report's discussion of reconditioning and reusing drilling muds fails to note that the ability to reuse mud economically varies widely with the distance between drilling operations, frequency and continuity of the drilling schedule and the compatibility between muds and formations among drilling sites.

- The statement that pits are <u>generally</u> built or excavated into permeable surface soils or into unconsolidated sediments is not correct. Pit construction practices recognize surface soil conditions and distances to groundwater. In fact, 37% of pits throughout the U. S. were lined to prevent potential seepage to groundwater. Many of these liners were necessary to comply with state regulations and permit conditions.

- The point (page 14) that disposal of drilling fluids down surface pipe is generally used when drilling fluids contain objectionable levels of contaminants is not correct. In fact, many operators use this technique because it is less expensive than hauling to remote disposal sites or treating the fluids to comply with discharge criteria (see Chapter VII.B. for state regulatory requirements). Moreover, this phase of pit closure does not address solids disposal. The disposal of solids is addressed by using burial, solidification, or landspreading techniques.

- The report stresses (page 16) that annual disposal has numerous problems. For example, the draft report implies that surface pipe does not adequately protect groundwater. State regulations require that surface pipe cover all USDW's and be cemented to the surface in newly drilled wells. Further, most states regulate when annuar injection can be used and limit injection pressures to prevent fracturing of the confining zone between the bottom of the surface pipe and lowermost USDW. Finally, most shallow shale beds are usually continuous in the major sedimentary basins.

- The statement (page 21) that "nationally, approximately 60 - 70 percent of all produced waters are disposed of in injection wells" is underestimated. This value should range from 80 - 90 percent.

- The report refers (page 32) to the potential for an injection formation becoming "pressurized" by having several high

pressure injection wells operating in an EOR project. A problem would then exist for migration of injected fluid to a USDW through improperly plugged wells. This is possible, but not likely. Water injection in enhanced recovery operations is not usually initiated until the pressure in the producing reservoir has declined significantly below the original reservoir pressure. Further, under the UIC program, all states either limit injection pressures or specifically permit an approved pressure. Most EOR projects are subject to constant pressure and volume monitoring, reducing the potential for this problem.

- The report discusses variation of state programs as if it implies corresponding variation in effectiveness. There are many valid reasons for variations, some of which are required by statute. For example, section 1425 of the Safe Drinking Water Act required EPA to recognize differences in state programs in awarding primacy. However, in 1981, the EPA office of Drinking Water issued minimum guidelines for assessing adequate state programs. These guidelines address permitting, area of review, enforcement authority, and other major requirements for assuring that a state program is acceptable. As a result, there may be certain state programs that are different but there is a minimum standard they must all meet to obtain primacy. These minimum standards imposed by EPA are adequate to protect USDW's.

- The report criticizes (page 35) the present UIC program as allowing the grandfathering of existing Class II wells thereby circumventing the responsibility of the operator to identify possible channels of communication between the injection zone and freshwater zones. The operator must report annually (and weekly or monthly depending on permit requirement) injection well pressures as required by the present regulations in both primacy and non-primacy states. The operator also must comply with MIT test requirements at least every five years and more frequently as required by their permits. More importantly, sound operations practices

dictate an operator observe the performance of its injection wells on a daily basis. The point is that the present program does not relieve the operator of maintaining compliance, i.e., preventing contamination of USDW's.

- The report's assessment of incentives (page 35) for assuring the integrity of disposal wells is incorrect. There are many types of waste disposal processes used in industry whereby the incentive for assuring proper disposal is environmental protection and regulatory compliance. There is also an economic incentive from the heavy fines and pipeline severances that can be imposed if the regulations are ignored. Further, the report states that most disposal wells are usually old, heavily patched and difficulty to maintain. This is not true. Many disposal wells are new because converting a producing well in the field would reduce crude oil production. Also, in many smaller fields, the salt water disposal (SWD) well is the difference between revenue and no revenue. If the injection well goes down, production has to be shut in. Moreover, most enhanced recovery wells are converted form producing wells. The idea that all disposal wells are old and heavily patched and enhanced recovery wells are new and without problems is incorrect.

- The report describes (page 36) the use of percolation and evaporation pits for areas where underlying waters are not suitable for use. However, the report then sees a potential for these same pits to contaminate usable ground water. This is a contradiction and such pits require state permits before they can be used for these purposes.

- In discussing surface water discharges the report alludes to the potential for damage to the aquatic communities from discharges. Industry has reviewed many studies of coastal estuaries and bays where aquatic life has been found to

coexist successfully with industry operations. A listing of these studies can be provided. Also, EPA itself has responsibility for regulating these discharges through enforcement of the Clean Water Act NPDES program and does not require additional authority under RCRA.

CHAPTER IV - DAMAGES CAUSED BY OIL AND GAS OPERATIONS

SUMMARY

- API's analysis centers on presenting information on the 62 cases contained in the Draft Report to Congress.

- Cases are analyzed and conclusions presented as to whether adequate regulations exist to regulate "damage" incidents regardless of whether API believed the cases are appropriate for inclusion in EPA's study. Adequate regulation exist in these cases.

- API continues to disagree that damage cases from outdated practices prevented by current regulations and non-waste, non-RCRA issues such as oil spills, producing operations and Clean Water Act discharges are appropriate for this study because the study was mandated by Congress to determine the need for additional waste management regulations.

- API is concerned that no questions were posed regarding its 500+ page submittal on the 228 cases included in the Interim Report. API is available to discuss any additional documentation needs or answer questions in whatever manner would be helpful to EPA.

- API is concerned the Draft Report refers to 249 or 21 cases not in the Interim Report's 228. If these and other cases are used for background or other purposes in the report, industry should be provided the opportunity to comment upon these cases. We are also concerned with the use of cases that did not pass EPA's "test of proof" for "overview discussions...and supporting the risk assessment." From the 62 cases API reviewed, the attached list of statements from the damage cases overview discussion do not appear to be supported.

- In analyzing the damage cases, API has provided a characterization of the cases compared to current regulations, a summary of cases by damage category and detailed comments on each care to supplement its original comments in EPA's docket.

Damage Case Overview Statements

Appalachian Basin..."Because of these marginal economic conditions, the costs of environmentally protective practices and proper well abandonment practices can make the difference between profitability and unprofitability."

Ohio..."The State has recently banned all saltwater disposal pits, but a current legislative initiative is attempting to overturn that ban."

West Virginia..."Enforcement is difficult both because of limited availability of State inspection and enforcement manpower and because of the remote location of many drill sites."

Pennsylvania..."In Pennsylvania, disposing of oil and gas wastes into streams prior to 1985 violated the State's general water quality criteria, but the regulations were rarely enforced."

West Virginia..."Land spreading of drilling muds containing up to 25,000 ppm chlorides is allowed."

Pennsylvania..."Even though spills are accidental releases, and thus do not constitute wastes routinely associated with the extraction of oil and gas under the sense of the Section 3001 exemption, "spills" in this area of Pennsylvania appear to represent deliberate, routine, and continuing illegal disposal of waste oil."

Louisiana..."drilling muds from onshore operations may be discharged into estuaries of the Gulf of Mexico, ...Since the muds can contain high levels of toxic metals, bioaccumulation of these metals in shellfish or finfish are of concern:"

Arkansas..."The State of Arkansas has limited resources for inspecting disposal facilities associated with oil and gas production."

Kansas..."Recently the Kansas Corporation Commission added new "lease maintenance" rules to their oil and gas regulations. The question of concern is how stringently these rules will be enforced, especially, as these cases show, in the light of the evident reluctance of some operators to comply even when faced with repeated orders for corrections."

Texas..."While the Texas Railroad Commission has not stopped the practice of coastal discharge, they are currently evaluating the need to preclude this type of discharge by collecting data from new applications."

Wyoming..."Enforcement of state regulations is made difficult as resources are scarce and areas to be patrolled are large and remote."

New Mexico..."Over 20,000 unlined produced water disposal pits are still in existence in New Mexico."

Alaska..."Inspection of oil and gas activities and enforcement of state regulations on the North Slope is difficult due to resource constraints, .."

DRAFT REPORT TO CONGRESS
DAMAGE CASE CHARACTERIZATION

CATEGORY	TOTAL NO. CASES	CASE WOULD VIOLATE CURR REGS	AGENCY STUDY OR NOT SITE SPECIFIC	OIL OR SW SPILL	ALLOWED OR PERMITTED DISCHARGE	CIVIL SUIT FOR DAMAGES	WORKOVER PROBLEM
DRILLING RELATED DAMAGES							
CONTAMINATION OF GND WATER FROM RESERVE PITS	5	4				1	
SURF DAMAGE-LANDSPREADING OF RESERVE PITS	1	1					
ALLOWABLE DISCHARGE OF MUDS ON GULF COAST	1	1					
ARTIC NORTH SLOPE DRILLING RESERVE PITS	4	1	3				
DAMAGE FROM KENAI AREA DRILLING	2	2					
SUBTOTAL DRILLING	13	9	3	0	0	1	0
PRODUCTION RELATED DAMAGES							
ILLEGAL DISPOSAL	17	16		1			
PROD WATER AND DISPOSAL PITS LEACHING	3	2	1				
ALLOWABLE DISCHARGE INTO STREAMS	4	1			3		
CONTAMINATION FROM UNDERGROUND INJECTION	6	6					
CONTAMINATION FROM IMPROPERLY PLUGGED WELLS	7	4	1			2	
DAMAGE FROM POOR LEASE MAINTENANCE	2	2					
DISCHARGE INTO THE TEXAS GULF COAST	3	1			2		
DAMAGE FROM ARTIC OPERATIONS	1	1					
DAMAGE FOLLOWING FRACTURING OPERATIONS	2	1					1
DAMAGE FROM OIL OR SALTWATER SPILLS	2			2			
IMPROPERLY COMPLETED PRODUCING WELLS	2	2					
SUBTOTAL PRODUCING	49	36	2	3	5	2	1
TOTAL NO. CASES	62	45	5	3	5	3	1

DRAFT REPORT TO CONGRESS SUMMARY OF
DAMAGE CASES BY CATEGORY

DRILLING RELATED CASES:

Contamination of Groundwater from Reserve Pits - 5 Cases (OH49,MI04,OK08,OK02,KS05)

- Only two of the five cases appear to be the result of Leachate from reserve pits (MI04 and OK08). In both cases the States have regulations addressing this type damage that would make it a violation today.

- Of the three remaining cases, OK02 is a civil suit case seeking damages for a 1973 drill well where the information from the plaintiff's attorney cannot be verified by the OCC or defendant. The two other cases OH49 and KS05 appear to be damages from old produced water pits. Nevertheless, Ohio and Kansas do have regulations that pertain to both reserve pit construction and operation and produced water pits that would have made these cases violations today.

- Additional regulatory authority or regulations are not justified by these cases.

Surface Damage Related to Landspreading of Reserve Pit Contents - 1 Case (WV13)

- West Virginia state regulations at the time of the discharge permitted landfarming of pit fluids with chloride levels above those discharged. Since then, revised regulations would have banned this landfarming incident (see case writeup for new regulatory limits).

- Existing regulations are adequate and can be changed if needed to reduce chloride limits in the future.

Allowable Discharge of Drilling Mud Into Gulf Coast Estuaries - 1 Case (LA20)

- Louisiana has regulations in place for discharges into inland and coastal waters. In this case, the state ordered a legal discharge stopped under its authority to regulate discharges.

- No additional regulatory authority is needed.

Damage from Arctic North Slope Drilling Reserve Pits - 4 Cases (AK06,AK07,AK08,AK12)

- Three of the cases are studies (AK06, AK07, AK08).

- Two of the studies (AK06, AK08) investigated the impacts of permitted discharges to the tundra. AK06 was a draft study by FWS that is unavailable to EPA or the public for review. ADEC drawing on AK08 and other information has recently promulgated new discharge requirements to additionally protect the tundra. The regulations were promulgated under existing authority.

- One of the studies (AK07) is not damage related and found only that reserve pits and Arctic ponds support different levels of Daphnia which is a species sometimes used in toxicity testing.

- One case AK12 is an example of a practice now banned by the ADEC. Exploration pits are now required to be closed within one year of cessation of operations and can no longer be left open indefinitely as was U.S. government's practice on the NPRA.

- The need for additional regulatory authority requirements or regulations are not demonstrated by these cases.

Damage Related to Alaska Drilling in the Kenai Area - 2 Cases (AK01,AK03)

- Both cases refer to sites that current regulations would prohibit using.

- One site (AK01) received materials initially from an oil and gas operator but became an open dump.

- One site was a commercial site which is no longer used and would not be in compliance with ADEC regulation 18 AAC 60.3106 requiring groundwater monitoring and other requirements for commercial sites.

- No additional regulation or regulatory authority is justified by these cases.

PRODUCTION RELATED CASES:

Illegal Disposal in Production Operations - 17 Cases (LA45,LA64,LA90,OH07,OH12,OH45,AR07,AR04,TX21,TX22,WY03,WY05,WV18, LA15,AR10,WV20,PA09)

- Sixteen of the incidents involve activities in violation of state or federal regulations for either waste disposal or reporting of oil spills as required under the Clean Water Act Section 311.

- One case (LA64) is an accidental saltwater spill incident where the landowner refused remedial action by the operator and demanded instead a cash settlement.

- Additional regulation is not justified as 16 of 17 of the cases are already illegal and the seventeenth was an accidental spill that should not have been included in this category.

Produced Water and Oil Field Waste Pit Contents Leaching Into Groundwater - 3 Cases (NM02,NM05,LA67)

- All three cases involve practices which are no longer authorized and are extensively regulated by the states of New Mexico and Louisiana.

- One case (NM02) was erroneously reported. No damage occurred, and no violation of state groundwater standards existed.

- No additional regulations are required or justified because these practices are no longer allowed.

Allowable Discharge of Water Into Surface Streams and Ephemal Streams - 4 Cases (WY07,CA21,CA08,PA02)

- Three of the cases are allowed discharges under the Clean Water Act's NPDES program. One (PA02) reports on a study on discharges that would violate state and federal NPDES requirements if they were occurring today.

- The surface discharge of produced waters (WY07) is specifically allowed west of the 98th meridian under the Agricultural and Wildlife Water Use provision of the Clean Water Act (40CFR Part 435 Subpart E). These discharges are extensively regulated under the federal NPDES programs implemented by the EPA and/or under existing state water quality standards. Further, many of these waters are of high quality and represent a major water source for many landowners in arid regions of the Western U.S.

- The California cases (CA21, CA08) represent an example of a situation that may require additional regulatory attention. Regulation of this type incident are covered under the Clean Water Act NPDES program. These cases are under active regulatory review using existing regulatory authority by the EPA and California. If changes are required, they will be incorporated into revised permit conditions.

- Further regulations are not justified based on documented damage or a lack of current regulatory authority from there cases.

Contamination from Improperly Plugged Wells - 7 Cases (KS03,KS14,TX05,TX11,TX15,LA65,KS03)

- Four of the cases (KS03,KS14,TX05,TX15) are examples of wells not plugged in accordance with current regulatory requirements. Current regulations require placing cement plugs across producing or injection zones and separate plugs immediately below USDW's to protect groundwater.

- One case (TX11) did not cite a specific well but alleged wide-spread salt seeps across Texas resulted from improperly abandoned wells. If the wells exist, the Texas Railroad Commission is responsible for properly abandoning them if the operator cannot be found.

- Two cases (LA65,KS03) are currently in litigation and the source of pollution and responsible parties has not been determined (see LA. Office of Conservation comments in EPA's docket on LA65 and KCC comments on KS03).

- No additional regulatory authority or regulations are justified by these cases.

Damage related to Lease Maintenance - 2 Cases (KS01,KS08)

- Both cases (KS01, KS08) involved violations to Kansas regulations. Further, these events occurred prior to the issuance of KCC's "Lease Maintenance Rules" (K.A.R. 82-3-600 through 603) in May 13, 1987. These rules require permitting of all pits (including drilling pits, previously not required by KDHE), emptying of emergency pits within 48 hours, notification of spills within 24 hours and specific administrative penalties for each violation.

- On July 1, 1986, KCC gained complete authority over all oil and gas activities. Prior to that date they shared certain aspects of environmental regulation authority with the KDHE. KCC, unlike KDHE, has the authority to shut down an operator should the situation require such action and is also staffed with more field agents.

- Existing regulations are adequate.

Discharge of Produced Water and Drilling Mud Into Bays and Estuaries of the Texas Gulf Coast - 3 Cases (TX55,TX31,TX29)

- All three cases were permitted by the Texas Railroad Commission and are subject to EPA regulation under the Clean Water Act.

- In two cases (TX55, TX31) no evidence of damage to tidal areas was documented.

- One case, TX29 where damage occurred to fresh water resulted in the discharge permit being revoked.

- No additional discharge regulations are warranted by these cases.

<u>Damage Related to Arctic Production Operations</u> - 1 Case (AK10)

- This case is an example of illegal storage and handling of used drums by a commercial salvage company. Alaska took action under 18 AAC 75.080 and required cleanup and monitoring of adjacent tundra and pond areas.

- No additional regulations are justified to regulate this type incident.

<u>Damage to Water Wells Following Fracturing Operations on Producing Wells</u> - 2 Cases (WV17,PA08)

- One case (WV17) resulted in a workover operation fracturing into groundwater as a result of equipment failure or accident. As described in the detail writeup this is not a normal result of fracturing as it ruins the productive capability of the wells.

- One case (PA08) is not the result of fracturing but of habitual violations of an operator who unsuccessfully sought bankruptcy to avoid state enforcement actions.

- No additional regulations are justified by these cases.

<u>Damage Related To Production Operations Spills</u> - 2 Cases (AK09,MI05)

- Both cases are spills with AK09 an oil spill and MI05 an oil and saltwater spill.

- Both state and federal regulations are in place to address such incidents. The Clean Water Act requires the preparation of Spill Prevention Control and Countermeasures (SPCC) plans under 40 CFR part 112. Also, immediate notification and prompt cleanup of Alaska oil spills are required under ADEC rules 18 AAC 75.080. The U.S. Coast Guard also has cleanup and enforcement responsibility under their regulations 33 CFR part 153.

- No further regulatory authority or regulations are justified by these incidents.

<u>Groundwater Contamination from Improperly Completed Wells</u> - 2 Cases (NM03,NM04)

- Both cases are violations of state producing regulations. In addition to states having authority for environmental protection, they are charged with preventing waste of natural resources.

- The Hobbs case (NM04) referencing oil on an aquifer uses 1965 data. Numerous regulations have been placed in effect since that time (see detailed case writeup).

- No additional regulations or regulatory authority are justified by these cases.

CHAPTER V - RISK ASSESSMENT

- Some API data (waste volumes, pit sizes) have been adopted by the Agency. Will the final report also use column leaching data, statistics for pit liners, or information on arsenic provided by API?

- This draft reflects few revisions to risk model scenarios for underground injection as well as reserve pits. Will API's suggested changes be incorporated into the final draft?

- In Chapter 2.C, EPA's contractor has evaluated "risk" posed by wastes by calculating ratios of waste concentrations to multiples of health based factors. These calculations and the constituents emphasized are inconsistent with the risk approach taken in Chapter V. Will these sections be removed from the final report to eliminate this inconsistency?

- API supports EPA's efforts to make its risk analysis region-specific. However, the description of the weighting process employed to accomplish this is extremely vague and unclear. Will this be clarified in the final report?

- The risk analysis still does not address actual cases of environmental damage for human health, aquatic organisms, or natural resources. will damage cases be addressed in final risk analysis?

- This draft still contains no conclusions concerning risks posed by these wastes. What preliminary conclusions has EPA drawn considering a) the very conservative 90% percentile worst case risk to human health from medium sized pits is rather low (1.6×10^{-6} for cancer. 6.3×10^{-5} for less severe hypertension), b) the occurrence of oil and gas activities in sensitive environments is rather low (less than 5-10% of any area affected) and c) there is no mention of damage documented in sensitive environments?

- Are there areas in the qualitative Arctic risk assessment where additional information that could be supplied by API would be useful?

- Appendix A contains waste analyses and comparisons to multipliers of health-based standards. Will the final report address the significance of the waste analyses and include comparisons to API results?

CHAPTER VI - COSTS AND IMPACTS

- We support the inclusion of API's 1985 "Production Waste Survey" into the data base used for this report. We also support the reduction of the decline rates and the use of current prices.

- API's concern that the extreme variation in the type of operations present in the oil and gas industry cannot be adequately represented by 21 model projects is still relevant.

- The national cost level projections in Table 11 indicate additional cost for disposal of 20% of produced water in the non-hazardous scenario. while the reason is not discussed, it appears that it replaces discharge points with injection wells. If so, the inclusion of surface discharges permitted under the NPDES program is inappropriate. These point sources are specifically excluded in 40 CFR Part 261 and should not be included in this study. Therefore, the intermediate scenario should indicate no change for the management of produced water.

- RCRA Subtitle C scenario is unclear regarding the onsite management of drilling waste. API has estimated the cost of drilling waste disposal in hazardous waste facilities at $25 per barrel versus EPA's contractors figure of $17.78 per barrel. The contractor's cost also appears low in view of additional costs that would be incurred for closed drilling systems or other equipment necessary to contain hazardous waste.

- The logic for the selection of waste management scenarios is not described. The report is unclear regarding whether the liners required for non-hazardous waste reserve pits in the "immediate scenario" would also be required in the "RCRA Subtitle C scenario." It is also not clear why the "RCRA

Subtitle C" scenarios assume that 10% or 70% of projects generate hazardous waste. If these percentages are based on sampling data, the basic information should be open to comment. However, if based on sampling data, the sample size may not be representative.

- The unit cost estimates from the Inerim Report serve as the basis for the national level Lower-48 composite model project. API has documented in previous comments our concern that the manner in which the dollar per barrel costs were calculated results in understated cost. These comments are still applicable. Using these values as a basis for modeling will result in an understated overall industry impact.

- It is unclear how the economic methodology will account for reductions in drilling activity. It appears the impact on newly discovered reserved may not recognize that, in addition to drilling costs, newly developed reserves will also have to support production costs associated with additional regulations.

- The costs per barrel for hazardous waste compliance depends on reserves used. The reserves used in the calculations in Table 10 should not be checked against DOE estimates to insure that they are not overstated, which would understate the impact on new project rates of return.

- It appears that impacts on commercial facilities are either overlooked or understated. The impact on existing commercial facilities that receive non-hazardous drilling waste is not included. Also, the impact of the increased demand on an already capacity-limited commercial hazardous waste disposal industry is not adequately addressed. This situation would serve to increase the unit cost of disposal dramatically under the RCRA Subtitle C Scenario.

- As commented upon in the Interim Report, costs of transportation under the RCRA Subtitle C scenario are underestimated.

The lack of hazardous waste disposal facilities in certain parts of the country, the impact of an overall lack of hazardous waste disposal capacity and the remoteness of oil and gas operations will all contribute to high transportation costs and all are inadequately addressed. Particularly understated is the assumption that a Class I well will be available within an average of 30 miles from oil and gas operations. It is also probably optimistic to assume that new Class I wells will be located the same distance from producing wells in new projects as a Class II facilities would have been.

- Costing of produced water management must recognize that 128,000 of industry's 168,000 Class II wells are used in enhanced oil recovery projects and cannot be relocated. This water must be reused onsite for reinjection in enhanced recovery operations. Conversions or replacement of these existing wells to strict Class I wells could also require workover or replacement of producing wells within areas of review.

- Development of baseline economic case data incorrectly assumes that average per well producing rates are typical producing rates. In fact, most wells produce at rates below the mathematical average rate. This assumption generates overstated initial producing rates that will understate the impact of additional regulatory costs.

- The derivation of economic limits based upon waste management costs should be discussed in more detail.

- The economic analysis methodology is limited to oil industry impacts on exploration, development, and production. It fails to address oil industry employment. It also does not address the major restructuring of state and national economics and employment losses outside the oil industry that would result from hazardous waste regulations.

CHAPTER VII - CURRENT REGULATORY PROGRAMS

The following comments address EPA's discussion on state regulatory programs.

- API believes that the information provided on current state regulations and damage cases must be incorporated into the chapters on current industry practices and risk assessment. Otherwise a through and fully accurate analysis of the adequacy of current regulations and industry practice cannot be conducted to satisfy the congressional mandate to determine if additional regulations are required.

- API's June 15th comments provide evidence that states actively enforce regulations. Damage cases involving violations of state regulations resulted in administrative or enforcement actions in 95% of the cases.

- Fines are not the only mechanism available to states to insure compliance. The permitting process is another tool. Permit review procedures take into account past compliance of the applicant. Special permit conditions, which can include specific reporting requirements, may also be applied on field conditions and/or past compliance history.

- Data, such as that submitted to the EPA contractor by states, should be utilized when studying the enforcement issue. The only state enforcement data used by the contractor concerns the number of field inspectors (Attachment A).

  Oklahoma, for example, submitted a package describing how they track the effectiveness of their regulatory program. This type of data should be included in an assessment of state regulatory effectiveness.

- Statistics like those submitted by Oklahoma should be incorporated into EPA's assessment of the state regulatory program's effectiveness. For example, the following comments were provided to amplify on Oklahoma's program (see attachment B).

  -- Field operations inspectors and managers achieved a high rate of success in resolving complaints and rules violations. Of 138,750 complaints investigated, 110,566 (79.68%) were resolved in the field. Only 206 complaints required legal action to obtain compliance.

  -- Installation of computers in the four district offices gave field personnel instant access to intent-to-drill and surety information.

  -- Field inspectors worked 122,535.5 man hours in FY86. The largest share (27.64%) was spent conducting inspections. The second largest share (14.07%) was spent investigating and resolving complaints.

- API generally concurs with EPA's assessment of state regulations. Several comments relative to specific state programs are included in attachment C.

ATTACHMENT A TO COMMENT ON CHAPTER VII - CURRENT REGULATORY PROGRAMS

State	Gas Production	Oil Production	Gas wells	Oil wells	Injection wells	New wells	Agency	Personnel
Alaska	316,000 Mmcf 1986	681,308,821 Bbls	104	1,181	472 Class II 425 EOR 47 Disposal	100 new onshore wells completed in 1985	Oil and Gas Conservation Commission Department of Environmental Conservation	3 enforcement positions
Arkansas	194,483 Mmcf. 1985	10,715,681 Bbls.	2,492	9,490	1,211 Class II 230 EOR 972 Disposal	1,065 new wells completed in 1985	Arkansas Oil and Gas Commission Department of Pollution Control and Ecology	7 enforcement positions 2 enforcement positions
California	483,000 Mmcf. 1985	423,860,000 Bbls	1,668	58,079	11,068 Class II 10,047 EOR 1,018 Disposal	3,413 new wells completed in 1985	Conservation Dept., Division of Oil and Gas Department of Fish and Game	31 enforcement positions
Kansas	466,600 Mmcf. 1984	76,723,000 Bbls.	12,680	67,833	14,902 Class II 9,366 EOR 5,536 Disposal	6,025 new wells completed in 1985	Kansas Corporation Commission	30 enforcement positions
Louisiana	5,867,000 Mmcf. 1984	449,545,009 Bbls	14,436	25,823	4,438 Class II 1,283 EOR 3,153 Disposal	5,447 new onshore wells completed 1985	Department of Environmental Quality Office of Conservation - Injection and Mining	32 enforcement positions 36 enforcement positions
New Mexico	893,300 Mmcf. 1985	78,500,000 Bbls	18,308	21,986	3,871 Class II 3,508 EOR 363 Disposal	1,747 new wells completed in 1985	Energy and Minerals Department, Oil Conservation Division	10 enforcement positions
Ohio	182,200 Mmcf. 1985	14,987,582 Bbls	31,343	29,210	3,958 Class II 127 EOR 3,829 Disposal	6,297 new wells completed in 1985	Ohio Department of Natural Resources, Division of Oil and Gas	66 enforcement positions
Oklahoma	1,996,000 Mmcf 1984	153,250,000 Bbls	23,647	98,030	22,803 Class II 14,901 EOR 7,902 Disposal	9,176 new wells completed in 1985	Oklahoma Corporation Commission	52 enforcement positions 58
Pennsylvania	166,000 Mmcf. 1984	4,825,000 Bbls. 1	24,060	20,739	6,183 Class II 4,315 EOR 1,868 Disposal	4,627 new wells completed in 1985	Department of Environmental Resources, Bureau of Oil and Gas Management	24 enforcement positions
Texas	5,806,000 Mmcf 1985	830,000,000 Bbls	68,011	210,000	53,141 Class II 45,223 EOR 7,918 Disposal	25,721 new wells completed in 1985	Texas Railroad Commission	120 enforcement positions
West Virginia	142,500 Mmcf 1986	3,600,000 Bbls 1	32,500	15,895	761 Class II 687 EOR 74 Disposal	1,839 new wells completed in 1985	West Virginia Department of Energy	
Wyoming	597,896 Mmcf 1985	130,984,917 Bbls	2,220	12,218	5,880 Class II 5,257 EOR 623 Disposal	1,735 new wells completed in 1985	Oil and Gas Conservation Commission Department of Environmental Quality	7 enforcement positions 4.5 enforcement positions

NORMA EAGLETON
Commissioner

ATTACHMENT B
TO COMMENT ON
CHAPTER VII - CURRENT REGULATORY PROGRAMS

TOWNSEND
Commissioner

OKLAHOMA

Corporation Commiss

JIM THORPE BUILDING

OKLAHOMA CITY, OKLAHOMA 73105

ATION DIVISION
7301

June 18, 1987

Ms. Carla Greathouse
Versar Inc.
6850 Versar Center
Springfield, VA 22151

Dear Ms. Greathouse:

This is in response to your verbal request for information concerning the organizational structure and responsibilities of the Oil and Gas Conservation Division of the Oklahoma Corporation Commission. Your special interest was directed to the Field Operations Department of this Division. Attached is information that we trust will satisfy that request.

There is always concern about how information such as you are being furnished will be used or interpreted. Based on some of the comments on pages 12 and 13 of chapter 3 of your Interim Report dated April 30, 1987 there is strong implication that the states are doing an inadequate job of taking care of their environmental business. In my judgment, much of what is written is suppositional and judgmental rather than factual. We in Oklahoma feel we have good regulatory programs with adequate, dedicated staff and enforcement capability to properly protect the state's environment.

Much of what is stated on pages 12 and 13 would, if applicable, be as difficult to contend with whether or not the programs are managed by state or federal agencies. In reality a well run state program has more sensitivity to site specific problems and is far more cost effective than a federal program.

With all due respect, we don't necessarily mean to be argumentive but having read much of the Interim Report it appears to have a strong anti-state bias.

The Oklahoma Corporation Commission has recently promulgated Soil Farming rules for utilization of fresh water drilling fluids and cuttings from reserve pits that we believe will be models for other states to follow. Further, we would be pleased to have your firm visit us for a firsthand appraisal of our regulatory efforts.

We are most pleased to furnish information we feel will be used in a constructive way, so should you have additional needs, please so advise.

Sincerely,

C. D. Davidson

C. D. Davidson, Director
Oil and Gas Conservation Division
Oklahoma Corporation Commission

:ph

attachments

1. Organization Chart - FY86 Annual report attached.

2. <u>Field Operations Staffing</u>

\- <u>Oklahoma City Department Staffing</u>

Manager -	1
Complaints Coordinator -	1
Field Inspector -	1
	3

<u>District I</u>

Manager -	1
Assistant Manager -	1
Office Staff -	2
Field Inspectors -	12
	16

<u>District II</u>

Manager -	1
Assistant Manager -	1
Office Staff -	2
Field Inspectors -	13
	17

<u>District III</u>

Manager -	1
Assistant Manager -	1
Office Staff -	2
Field Inspectors -	15
	19

<u>District IV</u>

Manager -	1
Assistant Manager -	1
Office Staff -	2
Field Inspectors -	11
	15

Total Staff 70
Plus four vacancies

3. <u>Duties of Field Inspectors</u>

Supervises, witnesses, tests and records data on well production potential, casing setting, cementing, bottom hole pressure, or gas-oil ratio. Investigates pollution complaints, confers with oil company personnel, land owners, and officials of other state agencies concerning such complaints; makes recommendations based on the findings; advises complainant of action taken. Checks field operations upon receipt of notice of intention to drill, work over, plug, and abandon wells to insure compliance with Commission rules and regulations. Inspects production and drilling practices to insure that rules and regulations pertaining to drilling, casing, cementing, plugging and abandonment, salt water disposal, use of earthen pits, and other operations utilized by the petroleum industry are complied with; reports violations. Investigates application for various permits and recommends approval or disapproval.

Oil & Gas Conservation Division

Charles D. Davidson, Director

The Corporation Commission is charged by statute to prevent waste of Oklahoma's hydrocarbon reserves, protect the environment from oil and gas-related pollution and preserve the correlative rights of all parties who have the right to benefit from the production and sale of oil and gas.

Administrative and technical phases of this responsibility are handled by the Oil and Gas Conservation Division. During FY86, the division operated at maximum strength of 134 clerical, technical and management specialists--63 in the Oklahoma City headquarters and 71 working in or from district offices at Bristow, Kingfisher, Duncan and Ada.

Charles D. (Jack) Davidson was named director of the Oil and Gas Conservation Division in December 1985. He was selected from among more than 100 candidates. Davidson assumed his duties just two months after retiring from Phillips Petroleum Co. as president and general manager of Phillips' Norway Exploration and Production Group, the company's North Sea operations group responsible for management of assets valued at about $7 billion. Davidson is a graduate of the University of Kansas, with a bachelor's degree in petroleum engineering and geology, and the Harvard Business School's Advanced Management Program. He worked for Phillips Petroleum 31 years.

New technical capabilities and additional responsibilities highlighted Oil and Gas Division activities in FY86.

The first two phases of the Well Data Maintenance System (WDMS), a computerized well information tracking and storage system, went on line in FY86. Those two phases--Surety and Intent-to-Drill--collect and process data concerning proposed wells from application for a drilling permit to spudding.

In March 1986, the division became the Oklahoma agent for the federal Environmental Protection Agency for a survey to locate underground tanks used for storage of petroleum products and other hazardous substances.

The survey was the first phase of a nationwide EPA program to protect people and the environment from leaking underground tanks. The division also established a LUST (Leaking Underground Storage Tanks) unit to work with the EPA on later phases of the federal program.

The Oil and Gas Division has four departments: Administrative, Field Operations, Pollution Abatement and Technical.

Administrative

The Administrative Department is responsible for document handling and processing, word processing, well records management, public information services and oil and gas production records.

The Well Records Section is the official repository for all geographic, geologic, and operational information about all oil and gas wells drilled, produced and abandonded in Oklahoma. The documents are available for public review and are primary research tools for Commission regulatory actions and industry planning of new drilling activities.

Steps were taken in FY86 to improve and enhance public accessibility to oil and gas records. To comply with the Open Records Act, which became effective Nov. 1, 1985, the Well Records Section established a copying station exclusively for making copies of paper records available for public purchase. In March 1986, a service window was installed to speed handling of requests for microfilm and microfiche records.

Revised Oil and Gas Rules and Regulations were published in January 1986. A charge of $6 per book was established to cover the cost of providing updates when rules are revised. The automatic update system assures that operators will always have current information available on the regulatory requirements of the Corporation Commission.

During FY86, the Well Records Section processed and filed 9,921 new records, a decline of 16% from the 11,827 new records in FY85. The decline resulted from a downturn in Oklahoma oil and gas activity.

The Information/Public Interest Sec-

Emergency Team members Tommy Duncan (left) and L. F. Fegal demonstrate life support equipment at a seminar on hydrogen sulfide survival. E-Team members are specially-trained field inspectors who assist law enforcement officers in oil field H_2S emergencies and teach H_2S safety.

tion was created in 1981 by the legislature as the Complaints and Information Department to serve as an advocate for mineral and surface owners in dealings with oil and gas producers and buyers.

Responsibilities have been expanded to include providing general information on oil and gas matters by telephone and distribution of printed materials. The name of this unit was changed in FY86 to project a more positive image and reflect a declining number of complaints received.

During FY86, the Information/Public iterest Section handled 10,006 public contacts, a 26.6% decline from the 13,648 contacts in FY84 and 13,639 contacts in FY85. In response, staffing was reduced from three to two investigators.

The Oil and Gas Production Allowables Section tracks production from approximately 102,000 oil wells and 25,000 gas wells to assure production does not exceed amounts authorized by the Corporation Commission. During FY86, 54 oil and 792 gas wells were identified as overproducing, and appropriate actions were taken to bring the wells back into compliance with Commission orders.

Field Operations

The Field Operations Department enforces rules and regulations for oil and gas wells and related structures such as reserve pits, disposal wells and pits, tank batteries and piping, and the movement and storage or disposal of crude oil, drilling chemicals and salt water.

The downturn in drilling activity not reduce the field inspectors' workload. While drilling decreased, well pluggings and well abandonments increased.

Pollution control was a top priority for field operations personnel in FY86. Inspectors investigated all proposed off-site disposal pit locations, checking for soil type, surface proximity of underground water and the engineering design of fluid disposal ponds. They also monitored operations of licensed pits and investigated pollution problems caused by unplugged abandoned wells, reserve pit cuts, illegal dumping of drilling wastes, oil spills and pipeline leaks.

Field operations inspectors and managers continued to achieve a high rate of success in resolving complaints and rules violations. Of 138,750 complaints investigated, 110,566 (79.68%) were resolved in the field. Only 206 complaints required legal action to obtain compliance.

Installation of computers in the four district offices gave field person instant access to intent-to-drill a surety information.

Field inspectors worked 122,535.5 man hours in FY86. The largest share (27.64%) was spent conducting inspections. The second largest share (14.07%) was spent

investigating and resolving complaints. Field operations personnel logged 886,159 vehicle miles and 52.8 helicopter flight hours in FY86.

Pollution Abatement

The Pollution Abatement Department evaluates environmental pollution situations and develops recommendations for corrective action. The department also coordinates research toward new techniques for dealing with contemporary oil field pollution problems.

Primary focus is on off-site disposal pits, abandonded oil and gas wells, soil farming and pollution violation enforcement. During FY86, department investigations led to recommendations for closing one pit and closing or reworking 10 others. The department also developed methods for improving evaporation in pits in eastern Oklahoma which were plagued by excessive rainfall.

Near the end of FY86, the Pollution Control Department formulated guidelines for a pilot study of soil farming, a method of disposing of certain types of drilling fluid wastes by mixing them into soil. The guidelines culminated an 18-month study in cooperation with other Pollution Control Coordinating Board member agencies to evaluate the feasibility of soil farming. The eventual goal of soil farming research is development of procedures that will allow safe soil farming of wastes as an alternative to off-site pit disposal.

In addition to dealing with specific pollution issues, the Pollution Abatement Department upgraded its off-site pit information inventory to improve tracking of all pits' operational status and problem history.

The department also developed guidelines for site suitability, to help avoid location of pits at geologically unstable or otherwise inappropriate sites. Studies also produced recommendations for changes to strengthen requirements for pit permitting, construction, operation, maintenance and closure.

To help reduce processing time and rocedures, an information booklet was developed for pit permit applicants. The booklet describes the permitting process, including information required by the Commission, and lists rules and regulations for pit operations.

Technical

The Technical Department provides a multitude of engineering and geological services.

A major Engineering Section activity in FY86 was processing and making recommendations on a large number of applications for hardship and distressed gas well status, due to the soft market for natural gas. A Commission priority schedule requires that gas purchased from Oklahoma producers be taken first from hardship and distressed wells--wells that would sustain damage if they are not produced.

The Engineering Section also processes applications for commingling of production (producing fluids from more than one formation through a single tubing string) and venting and flaring of natural gas, reviews production information needed to determine if a well should be classified as a gas well or oil well, and recommends amendments to special field rules as safeguards to prevent production and pollution problems in individual fields.

The Geology Section investigates all geologic aspects of drilling for and producing oil and gas. This includes screening drilling permit applications to make sure the proposed drilling plan and location meet state requirements for fresh water and environment protection.

The Geology Section also collects, checks and records surface casing, electric logs and cement bond logs data. The data are monitored to determine compliance with Corporation Commission rules and regulations.

During FY86, the Technical Department began a prehearing screening process for well spacing, location exception and increased density applications.

This allows discovery and resolution of many technical problems prior to hearings, reducing the cost and time of delays required to settle technical disputes after hearings have been conducted.

During FY86, the Technical Department reviewed 1,560 spacing, 1,650 location exception and 1,098 increased density applications. The review process resulted in disapproval recommendations for 574

(13.32%) of the 4,308 applications reviewed.

The Natural Gas Policy Act (NGPA) Section classifies gas wells in Oklahoma according to categories established by the federal Natural Gas Policy Act of 1978. Classification is required to permit operators to sell natural gas at price levels established for each of the categories.

Classification applications require from four months to eight months for processing due to a backlog of applications and the complex geological and engineering data that must be evaluated to match each well's profile against federal NGPA requirements that define well categories.

Although about 60% of the nation's natural gas supply was deregulated in early 1985, the NGPA Section operated at full capacity in FY86. The NGPA Section received 3,173 classification applications and processed 4,179 applications. At the end of the year, approximately 850 filings were awaiting processing with additional applications being received at a rate of about 250 per month.

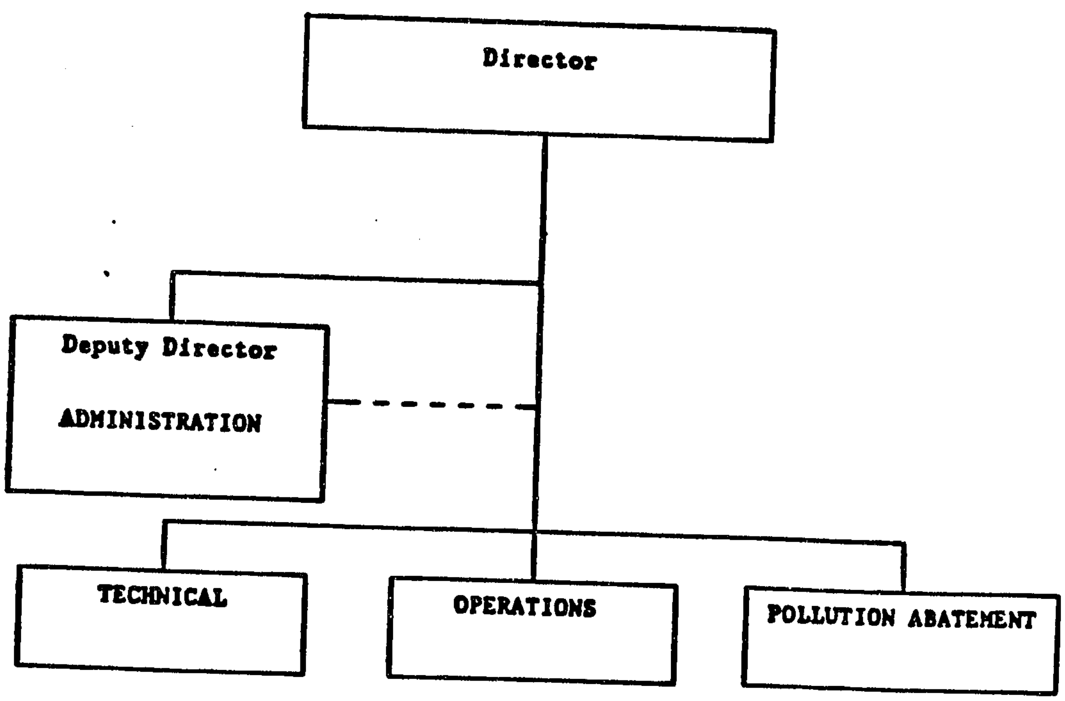
The Underground Injection Control Section protects underground fresh water supplies by assuring that underground wells used for disposal of salt water and injection of fluids in enhanced oil and gas recovery projects are constructed and operate properly.

The UIC Section processes injection well applications to determine site suitability and well construction requirements, and recommends issuance or denial of permits. During FY86, the UIC received and processed 1,049 applications for various types of injection wells and recommended 915, or 87.2%, for permitting.

Through inspections and testing, the UIC monitors well operations to assure mechanical integrity in accord with federal Environmental Protection Agency standards for protection of underground fresh water. Well monitoring is done by Oil and Gas Division field inspectors and through subcontracts with the Oklahoma Department of Health.

UIC information files and control procedures are being upgraded in anticipation of increasing injection well activity as Oklahoma's mature oil fields require more and more secondary and tertiary recovery work to produce remaining hydrocarbon reserves.

OIL & GAS CONSERVATION DIVISION



OIL & GAS CONSERVATION DIVISION - FY86 WORK LOAD DATA

SUMMARY OF DISTRICT FIELD OPERATIONS (EXPRESSED IN MAN-HOURS WORKED)

WORK CATEGORY	District # 1 (NE)	District # 2 (NW)	District # 3 (SW)	District # 4 (SE)	Field Total	% of Total
Underground Injection Control	5554.5	2458	3983	4663	16568.5	13.52
Well Testing	185	3017	915	868	4985	4.07
Complaints Investigation	4359	3473	7170.5	2238	17240.5	14.07
Inspections	7426.5	6099	8506	11840	33871.5	27.64
Consultations	3431	4275	3789	3866	15361	12.53
Water Analysis	84	296	326	188	894	0.73
Reports	2713.5	2467.5	2648.5	2599	10428.5	8.51
Court Testimony	522.5	204	286	285.5	1298	1.06
Meetings/Conf.	1844	2566	2062	1585.5	8057.5	6.58
Well Pluggings	2180	4879	4116	2656	13831	11.29
TOTALS	28300	29934.5	33712	30789	122535.5	100.00
TRAVEL MILES	210,294	226,869	223,713	225,283	886,159	
TRAVEL COST	$43,110	$46,555	$45,800	$46,183	$181,648	

INTENT TO DRILL APPLICATIONS

Fiscal Year	Appl.	Approved	% Appr.	Disappr.
1980	17,147	14,915	86.98	2,232
1981	24,509	21,477	87.63	3,032
1982	22,679	20,996	92.58	1,683
1983	15,306	14,516	94.84	790
1984	16,147	15,346	95.04	801
1985	14,482	13,992	96.62	490
1986	10,288	9,988	97.09	300

NGPA APPLICATIONS

Fiscal Year	Appl.	Withdrawn	Backlog	Deter.
1980	3,950	193	3,571	3,818
1981	5,165	132	3,162	5,442
1982	6,931	154	3,921	6,018
1983	5,223	137	2,452	6,555
1984	4,261	112	1,161	5,440
1985	4,237	113	1,266	4,019
1986	3,173	119	850	4,179

	WELL RECORDS PROCESSED & FILED	CERTIFICATES OF NON-DEVELOPMENT
1980	8,709	7,512
81	11,470	19,204
82	15,613	30,019
1983	17,845	12,919
1984	18,691	16,837
1985	11,827	10,779
1986	9,921	7,988

UNDERGROUND INJECTION CONTROL - FY 86

Permits For:	Appl.	Appr.	% Appr.
Salt Water Disposal	481	450	93.56
Enhanced Recovery Injections	443	362	81.72
Annular Injection	92	84	91.30
Secondary Recovery Units	15	9	60.00
Commercial Disposal Wells	18	10	55.56
TOTALS	1,049	915	87.23

INFORMATION & PUBLIC SERVICE - PUBLIC CONTACTS

Fiscal Year	Walk-In	Letters	Telephone	Total
1983	653	912	7,262	8,827
1984	746	872	12,030	13,648
1985	689	973	11,977	13,639
1986	557	707	8,742	10,006

ATTACHMENT C

TO COMMENT ON

CHAPTER VII - CURRENT REGULATORY PROGRAMS

- In addition to State laws and regulations governing: 1) Reserve Pit Design, 2) Construction and Operation, 3) Reserve Pit Closure/Waste Removal, 4) Produced Water Surface Discharge Limits, 5) Produced Water Injection Well Construction, and 6) Well Abandonment/Plugging, the Bureau of Land Management strictly regulates these activities on federally controlled lands under 30 CFR.

  Specific comments include:

- California - Table 4, "Produced Water Surface Discharge Limits." Column titled "Onshore" should be deleted as this is not a limitation.

- Louisiana - Table 2, "Reserve Pit Closure/Waste Removal." Column titled "Surface Water Discharge" should include a statement that "discharges must conform to applicable State and Federal discharge programs." These programs may require additional limits other than those stated and this column should incorporate that fact.

- New Mexico - Table 5, "Produced Water Injection Well Construction." Column "MIT Pressure and Duration". Rule 704 states that a minimum pressure of 300 psi should be used unless an exception is obtained from the New Mexico Oil and Gas Commission.

- Oklahoma - Table 3, "Produced Water Pit Design and Construction." Column "General Statement of Objective/Purpose" should delete ..."in addition offsite pits must contain fluids with less than 3,500 ppm Cl." This should be replaced with "General and Area guidelines provide specific design and construction limits for commercial and non-commercial reserve pits."

- W. Virginia - Table 2, "Reserve Pit Closure/Waste Removal." Column "Surface Water Discharge" should include the statement "Permit Req'd. Discharges unfit for domestic livestock or other general use prohibited." This is applicable to reserve pits also.

- Texas - Table 4, "Produced Water Surface Discharge Limits" Column "Coastal/Tidal" should delete ..."but skimming required to prevent oil in tidal waters." This should be replaced with "discharges must meet 15 mg/l Oil and Grease limit."

- Ohio - Table 2, "Reserve Pit Closure/Waste Removal." Column "Land Disposal/Application" should delete "Drilling fluids may be disposed of by land application." This should be replaced with "contamination of the surface of the land is prohibited."

  The Column "Road Application" should include "Individual Permit; Specifications Prescribed in Regulation." Ohio law permits local Government to allow surface application of brine. "Brine" has a broad definition and includes drilling fluids.

- Arkansas - Table 1, "Reserve Pit Design, Construction Design and Operations." Column "General Statement of Obejctive/Purpose" should delete ..."but regulatory basis and legal enforceability not supported by (OGC)." This is not correct. The Oil and Gas Commission (OGC) has authority over the oil and gas industry and takes an active part in enforcing rules and regulations applicable to the O&G industry. The Department of Pollution Control and Ecology (DPCE) has authority to enforce environmental laws and regulations. OGC and DPCE work together to see that the O&G industry is in compliance.

- Wyoming - Table 4, "Produced Water Surface Discharge Limits." Column "Beneficial Use" should contain "Same As Onshore."

CONTAMINATION OF GROUNDWATER FROM RESERVE PITS

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
OH49	PROD		Y		Y			NOT LIST	GND WTR	MUD		DAMAGE TO FRESH WATER WELL, INSUFFICIENT DETAIL ON EXACT SOURCE

THE SOURCE OF DAMAGE TO THE FRESH WATER WELLS IS UNCERTAIN. IT WAS UNDETERMINED WHETHER DAMAGE WAS RELATED TO DRILLING OR MORE LIKELY FROM WATER ANALYSIS OLD PRODUCTION PITS.
THE EPA CONTRACTOR DESCRIPTION OF OPERATIONS LISTS THE CATEGORY AS "PRODUCTION".
IN ANY CASE, THE CASE IS A VIOLATION OF CURRENT OHIO REGULATIONS REGARDING DRILLING MUD AND PRODUCED WATERS.
OHIO REGULATIONS FOR DRILLING MUDS: 1) PROHIBIT ESCAPE OF BRINE AND CONTAMINATION OF LAND, SURFACE WATER AND GROUNDWATER 2) REQUIRE LINERS IN HYDROGEOLOGIC BASINS (LINERS WOULD BE REQUIRED IN THE AREA OF THIS DAMAGE CASE). ALSO,
OHIO REGULATIONS FOR PRODUCED WATER REQUIRE SURFACE PITS CONTAINING PRODUCED WATER MUST BE LIQUID TIGHT, PRODUCED WATER CANNOT BY STORED MORE THAN 180 DAYS AND PITS CANNOT BE USED FOR ULTIMATE DISPOSAL.

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
MI04	PROD/DRLG PIT		Y		Y			NOT LIST	GND WTR	MUD/PROD WTR		1975 CASE DEALING WITH UNLINED PITS CURRENTLY BANNED

THIS CASE OCCURRED IN 1975. SINCE 1975, MICHIGAN HAS ADOPTED REQUIREMENTS (299.1304; 299.1601FF) FOR THE USE OF LINED PITS IS THIS AREA.

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
OK08	DRLG				Y			MI-WISC	GND/SURF WTR & SOIL	MUD	Y	LEAKING PIT IN VIOLATION OF OCC RULES ORDERED CLOSED

IN THIS CASE, EPA'S CONTRACTOR INCLUDED STATE COMMENTS WHICH UNDERLINE THE FACT THAT THE OCC ACTED ON A COMPLAINT BY A LANDOWNER AND DIRECTED THE OPERATOR TO REMOVE THE CONTENTS OF A PIT THAT VIOLATED OCC RULES BY CONSTRUCTION OF THE PIT IN A FRACTURED SHALE. FURTHERMORE, THE OCC IS IN THE PROCESS OF DEVELOPING ADDITIONAL REGULATION TO PREVENT THE LEACHING OF HIGH SALT MUDS INTO GRPUNDWATER.
IN ADDITION, COLUMN TESTS CONDUCTED IN THE API PRODUCTION WASTE STUDY AS WELL AS RESEARCH CONDUCTED BY DR. L. CANTER OF THE UNIV. OF OKLAHOMA ENVIRONMENTAL DEPARTMENT PRESENTED AT THE 1986 DRILLING MUD SYSPOSIUM IN NORMAN OKLAHOMA CONCLUDE THAT METALS OF CONCERN ARE VERY TIGHTLY HEALD IN DRILLING MUDS BENTONITE CLAY MOLECULAR STRUCTURE AND THERE IS NO DATA TO SUPPORT POLLUTION MIGRATION OF BARIUM, CHROMIUM OR ARSENIC.

OK02	DRLG	Y	Y	Y	NOT LIST	SURF/GND WTR & SOIL	MUD	1973 CLOSED DRILLING PIT ALLEGEDLY SEEPING INTO SURF WTR., CASE PENDING

API COMMENTS IN EPA'S DOCKET INDICATE NO DAMAGE HAS BEEN DOCUMENTED FROM THIS CASE. EPA'S CONTRACTOR IS REPORTING ON A CASE WHERE THE ONLY DATA SOURCE USED IS THE PLAINTIFFS ATTORNEY IN A PENDING LAW SUIT IN CIVIL COURT FOR DAMAGES. API'S COMMENTS WHICH WERE REJECTED FOR A LACK OF DOCUMENTATION WERE OBTAINED FROM THE OKLAHOMA CORPORATION COMMISSION AND THE DEFENDANT'S ATTORNEY. API IS CONCERNED THAT EPA'S CONTRACTOR MAY BE USING A DIFFERENT STANDARD FOR DOCUMENTATION FOR THEIR INFORMATION THAN API'S.
THIS CASE IS AN EXAMPLE OF DIFFICULTIES USING DATA FROM PENDING LAW SUITS WHERE FACTS HAVE YET TO BE EVALUATED AND JUDGEMENTS MADE BY THE COURT.
NEVERTHELESS, OKLAHOMA HAS PERFORMANCE STANDARDS PROHIBITING LEAKAGE OF RESERVE PITS INTO GROUNDWATER (SEE OK08 COMMENTS FOR ADDITIONAL DETAILS)

KS05	DRLG	Y		Y	NOT LIST	GRN WTR	SALT WTR Y	UNLINED DRILLING PIT THOUGHT TO BE LEACHING SALT INTO FRESHWATER WELL

KDHE AND KCC HAVE SUBMITTED COMMENTS IN EPA'S DOCKET SUBSTANTIATING THAT THE POLLUTION SOURCE WAS NOT THE REFERENCED DRILLING RESERVE PIT. EPA'S CONTRACTOR DISPUTES THE STATE AGENCY FACTS DESPITE EXTENSIVE INVESTIGATION INTO THIS INCIDENT BY TWO STATE AGENCIES.
NEVERTHELESS, KANSAS ISSUED "LEASE MAINTENANCE" RULES ON MAY 13, 1987 THAT SHOULD SERVE TO PREVENT THIS TYPE DAMAGE. THE RULES REQUIRE PERMITS FOR ALL PITS (DRILLING AND PRODUCING), EMPTYING OF EMERGENCY PITS WITHIN 48 HOURS, NOTIFICATION OF SPILLS WITHIN 24 HOURS AND SPECIFIC PENALTIES APPLICABLE FOR EACH VIOLATION. IN ADDITION, KCC HAS AUTHORITY TO SHUTDOWN AN OPERATOR TO ENFORCE ITS REGULATIONS.

SURFACE DAMAGE RELATED TO LANDSPREADING OF RESERVE PIT CONTENTS

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
WV13	DRLG				Y			TOWER DRLG	SOIL	MUD	-	LANDFARMING OF DRILLING MUDS DAMAGED VEGETATION FROM SALT CONTENT

THIS CASE DOES NOT DEMONSTRATE A NEED FOR ADDITIONAL REGULATION
THE CASE IS IN ERROR REGARDING STATE REGULATIONS ON ALLOWABLE LANDSPREADING
SINCE THIS INCIDENT ADDITIONAL REGULATIONS HAVE BEEN PROMULGATED LIMITING CHLORIDES LANDSPREAD TO 12,500 PPM, NO DISCHARGES OVER 25,000 GALLONS PER ACRE AND NO CHLORIDE LOADINGS OVER 600 LB PER ACRE.
WVDNR COMMENTS TO EPA'S INTERIM REPORT PROVIDE ADDITIONAL DOCUMENTATION AND STATE
DAMAGE FROM THIS 1986 INCIDENT WAS SHORT TERM AND HAS FULLY RECOVERED.

ALLOWABLE DISCHARGE OF DRILLING MUD INTO GULF COAST ESTUARIES

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND- ING CASE	VIOLATES CURR REGS	UNSUB- STAN- TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIN RESOURCE	CONTAIN WASTE	ADMIN/ ENFORCE- MENT ACTION	EPA CASE DESCRIPTION
LA20	DISCHARGE	Y			Y	Y		WOODS PET	SURF WTR	MUD	Y	PERMITTED DISCHARGE OF MUD THAT STATE ORDERED STOPPED

THIS CASE DOES NOT DEMONSTRATE A NEED FOR ADDITIONAL REGULATION AND CONTAINS SEVERAL ERRORS.
THE DISCHARGE FROM THIS 1985 DRILLING OPERATION WAS INITIALLY AUTHORIZED BY THE WPCD.
UPON ADDITIONAL STUDY, THE WPCD ORDERED THE DISCHARGE DISCONTINUED DUE TO ITS PROXIMITY TO OYSTER BEDS. THE STATE FILE CONTAINS NO INFORMATION ON DAMAGE TO THE OYSTERS OR BIOACCUMULATION.
THE STATEMENTS ABOUT MUDS CONTAINING HIGH LEVELS OF TOXICS IS UNSUBSTANTIATED.
SINCE 1985, LOUISIANA HAS ADOPTED ADDITIONAL REGULATIONS CONTROLLING DISCHARGES INTO INLAND AND COASTAL WATERS UTILIZING INDIVIDUAL PERMITS. IN ADDITION, OPERATORS ARE NOT ALLOWED TO DISCHARGE WITHIN 1300 FEET OF OYSTER BEDS.
THE CASE SHOULD REFLECT STATE ACTION (PERMITS) ARE REQUIRED TO DISCHARGE AND NOT TO CEASE DISCHARGES
ADDITIONAL DOCUMENTATION MAY BE FOUND IN STATE FILE NO. GP00249A

DAMAGE FROM ARTIC NORTH SLOPE DRILLING RESERVE PITS

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
AK06	DISCH/PIT					Y		N/S OPERATORS	SURF WTR	MUD		DRAFT STUDY OF PERMITTED DISCHARGES
AK07	DISCH/PIT					Y		N/S OPERATORS	SURF WTR	MUD		STUDY OF RESERVE PIT FLUID TOXICITY ON DAPHNIA
AK08	DISCH/PIT					Y		N/S OPERATORS	SURF WTR	MUD		STUDY OF EFFECT OF DRILLING FLUIDS ON FISH AND WATERFOWL HABITAT
AK12	DISCH/PIT		Y		Y			US GOVERNMENT	WTR/SOIL	MUD		NPRA RESERVE PIT FAILURE DUE TO PAST US GOVERNMENT DRILLING PRACTICES

AK06: AK06 IS A REPORT ON CONCERNS RAISED BY STUDIES CONDUCTED ON RELEASES FROM RESERVE PITS. THE REPORT WAS CRITICIZED FOR LACK OF TECHNICAL SOUNDNESS AND FWS WILL NOT RELEASE A FINAL STUDY FOR REVIEW TO EITHER THE STATE OR INDUSTRY. THEREFORE, IT IS IMPROPER TO CHARACTERIZE THE STUDY DRAFT FINDINGS AS "DAMAGES". IT SHOULD ALSO BE NOTED THAT ALASKA DELIBERATED OVER THE ALLOWABLE DISCHARGE LIMITS FOR THE CONTAMINANTS OF CONCERN (EG METALS). PUBLIC HEARINGS WERE CONDUCTED. AS A RESULT, THE ALASKA DEPARTMENT OF ENVIRONMENTAL CONSERVATION (ADEC) BELIEVES THAT THE PERMITTED DISCHARGES TO THE TUNDRA DO NOT POSE A THREAT TO HUMAN HEALTH OR THE ENVIRONMENT.

AK07: AK07 IS ALSO A FISH AND WILDLIFE STUDY THAT DRAWS UNSUBSTANTIATED CONCLUSIONS. REPORT FINDINGS SUBSTANTIATED ONLY THAT RESERVE PITS AND ARCTIC PONDS DIFFER IN ABILITY TO SUPPORT DAPHNIA POPULATIONS. DAPHNIA ARE A SPECIES BEING CONSIDERED FOR USE AS A TOXICITY INDICATOR. SEE ALSO COMMENTS ON AK06 REGARDING TUNDRA DISCHARGES.

AK08: AK08, LIKE AK06 AND AK07 SHOULD NOT BE CHARACTERIZED AS A DAMAGE CASE. IT DOES NOT ESTABLISH A LINK BETWEEN ELEVATED LEVELS OF ORGANIC OR INORGANIC COMPOUNDS IN PONDS AND LOWER PRODUCTIVITY OF THOSE PONDS. FURTHER, THE STUDY IGNORES THE FACT THAT RESERVE PIT DISCHARGES ARE PROHIBITED WITHIN ONE YEAR OF THE LAST PIT USAGE AND THAT NATURAL RUNOFF DURING THE SPRING THAW EFFECTIVELY "FLUSHES" THE TUNDRA AND WOULD PREVENT THE ACCUMULATION OF ORGANIC/INORGANIC COMPOUNDS IN TUNDRA PONDS. SEE ALSO COMMENTS ON AK06 REGARDING RUNDRA DISCHARGES.

AK12: AK12 IS AN NPRA RESERVE PIT WHICH FAILED AFTER OPERATIONS CEASED. PAST US GOVERNMENT DRILLING PRACTICES IN THE NPRA WERE TO LEAVE RESERVE PITS FOR EXPLORATION WELLS OPEN INDEFININITELY. HOWEVER, CURRENT REGULATIONS REQUIRE THAT DRILLING PITS BE CLOSED WITHIN ONE YEAR FROM THE CESSATION OF OPERATIONS. IT SHOULD ALSO BE NOTED THAT WELL SITE PLANTS WERE GROWING VIGOROUSLY BY THE TIME THE SITE ASSESSMENT WAS COMPLETED IN 1984.

DAMAGE RELATED TO ALASKA DRILLING IN THE KENAI AREA

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
AK01	GRAVEL PIT		Y	Y	Y		Y	UNION	WTR/SOIL	MUD/SW	Y	UNION WAS ORDERED TO CLEAN UP A DUMP SITE

THIS CASE INVOLVES DISPOSAL OF SPOIL MATERIAL WHICH WAS UNREGULATED PRIOR TO 1972. NO EVIDENCE OF GROUNDWATER CONTAMINATION WAS EVER FOUND. CLAIMED HEALTH EFFECTS BY NEIGHBORING RESIDENTS ARE ALL BY INDIVIDUALS RESIDING UP THE GROUNDWATER GRADIENT OF THE GRAVEL PIT AND WHOSE WELL WATER HAS NEVER SHOWN ANY SIGN OF CONTAMINATION. CURRENT REGULATIONS PROHIBIT DUMPING ON THIS SITE. GENERAL REGULATORY REQUIREMENTS ARE COVERED IN ADEC REGULATION 18 AAC 60.520.

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
AK03	COMMERCIAL COMPANY		Y		Y			MAR ENTERPRISE	GND WTR	MUD/PROD WASTE		ALLEGED PERMIT VIOLATIONS AT STATE PERMITTED DISPOSAL SITE

THE IMPACT IN THIS CASE IS NOT DUE TO DRILLING ACTIVITY BUT RATHER OF IMPROPER HANDLING BY AN INDEPENDENT COMMERCIAL WASTE DISPOSAL OPERATOR. ACTIVITY AT THE SITE IS LLLEGAL PER ADEC REGULATION 18 AAC 60.3106 WHICH REQUIRES QUARTERLY REPORTING AND GROUNDWATER MONITORING PROGRAMS.

ILLEGAL DISPOSAL IN PRODUCTION OPERATIONS

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
LA45	DISCHARGE				Y			KEDCO OIL	SURF/GND WTR & SOIL	PROD WTR	Y	ILLEGAL DISCHARGE OF PRODUCED WATER TO FRESHWATER SWAMP

THE OPERATOR OF A PRODUCTION FACILITY INSTALLED A PIPE AND DISCHARGED PRODUCED WATER INTO A FRESHWATER SWAMP WITHOUT A PERMIT. THIS VIOLATES STATE AND FEDERAL REGULATIONS. THE STATE AGENCY INSPECTED THE SITE AFTER COMPLAINTS AND ISSUED KEDCO A NOTICE OF VIOLATION. THE OPERATOR WAS FINED $ 9,500.

LA64	PROD	Y						SUN	SOIL	PROD WTR		ALLEGED IMPROPER SALTWATER DISPOSAL

THIS CASE ALLEGES THAT THE OPERATOR PURPOSELY DISCHARGED SALTWATER ON AN ADJACENT CANE FIELD CAUSING SEVERE DAMAGE TO THE CROP. THE FACT IS AN ACCIDENTAL LEAK OCCURRED AT THE FACILITY WHICH CAUSED THE PROBLEM. THE OPERATOR HIRED A CONSULTANT TO DEVELOP A PLAN TO RECLAIM THE LAND, BUT THE FARMER WOULD NOT COOPERATE. THE FARMER WANTED DAMAGES AND WOULD NOT ALLOW THE OPERATOR TO RECLAIM THE SITE. THIS CASE SHOULD NOT BE USED IN THIS CATEGORY.

LA90	COMMERCIAL SITE			Y	Y	Y	Y	CHEVCO/KENGO	SURF/GND WTR & SOIL	WASH WTR		ALLEGED DISCHARGE OF VACUUM TRUCK WASH WATER TO COULEE

THIS CASE ALLEGES THAT THE OPERATOR PURPOSELY DISCHARGED WASH WATER INTO A ROADSIDE DITCH LEADING TO A COULEE IN VIOLATION OF STATE LAWS AND REGULATIONS. NEARLY ALL OF THE CASE DESCRIPTION OF THREATS TO HEALTH AND THE ENVIRONMENT ARE NOT DOCUMENTED IN STATE FILES. IN FACT, THE STATE AGENCY FELT THAT THE DISCHARGE WAS AN ACCIDENT AND NOT ILLEGAL DUMPING. THE STATE DID NOT ISSUE A NOTICE OF VIOLATION. THIS CASE SHOULD BE REMOVED FROM THIS CATEGORY BECAUSE 1) THE OPERATOR DID NOT PURPOSELY DISCHARGE AND 2) THE FACTS IN THE CASE ARE SUSPECT.

NEVERTHELESS, LOUISIANA REGULATIONS PROHIBITS THE ALLEGED TYPE OF DISCHARGE.

IT SHOULD BE FURTHER NOTED, THE PLANTIFF'S ATTORNEY STATED 5/22/87 THAT THIS CASE IS CURRENTLY IN LITIGATION AND HAS NOT BEEN SETTLED OUT OF COURT AS DESCRIBED IN EPA'S CONTRACTOR REPORT.

OH[illegible]	DISCHARGE		Y	EQUITY	SURF WTR	PROD WTR Y	ILLEGAL DISCHARGE OF PRODUCED WATER
	THIS IS AN ILLEGAL DISCHARGE THAT VIOLATED OHIO REGULATIONS. OPERATOR WAS CITED AND CEASED PRACTICE.						
OH12	DISCHARGE	Y	Y	ZENITH	SURF/GND WTR & SOIL	PROD WTR Y	ILLEGAL PIT DISCHARGING PRODUCED WATER TO SURFACE DITCH
	THIS IS AN ILLEGAL DISCHARGE THAT VIOLATED OHIO REGULATIONS. OPERATOR WAS CITED AND FINED. ADDITIONAL RULE MAKING SINCE INCIDENT - SB 501 - PROHIBITS PRODUCED WATER DISPOSAL PITS AFTER 7/1/86.						
OH45	DUMP		Y	MILLER S&G	SURF/GND WTR & SOIL	MUD/PROD WTR	SAND AND GRAVEL PIT USED ILLEGALLY TO DUMP WASTE
	THIS CASE ALLEGES THAT AN ACTIVE SAND AND GRAVEL PIT WAS USED AS AN ILLEGAL DUMPING SITE FOR OILFIELD WASTES. AN INVESTIGATION BY THE OHIO DIVISION OF WASTEWATER POLLUTION SHOWED THAT CONTAMINATION OF THE SURROUNDING SWAMP WAS OCCURING. THIS DISCHARGE IS PROHIBITED BY STATE REGULATIONS. ADDITIONAL REGULATIONS HOWEVER COULD NOT PREVENT THIS TYPE OF IMPROPER ACTION.						
AR07	OIL SPILL	Y	Y	J LANGLELY	SURF/GND WTR & SOIL	PROD WTR/ OIL	OIL SPILL ILLEGALLY NOT REPORTED THAT DAMAGED ADJACENT PROPERTY
	THIS IS A NON-RCRA OIL SPILL INCIDENT RATHER THAN ILLEGAL DUMPING. ARKANSAS REQUIRES REPORTING OF SUCH SPILLS.						
AR04	PROD		Y	J. ROBERTSON	SURF/GND WTR & SOIL	PROD WTR Y	ILLEGAL DISCHARGE OF PRODUCED WATER TO BLACK CREEK
	THIS DAMAGE CASE DESCRIBES VIOLATIONS OF DRILLING PERMIS ISSUED TO THE OPERATOR. IT APPEARS THE OPERATOR CONSTRUCTED ILLEGAL ROADS, PITS AND WELL LOCATIONS IN VIOLATION OF PERMIT CONDITIONS. AS A RESULT, DESTRUCTION OF WETLANDS RESULTED. THE DAMAGE CASE ALSO ALLEGES THAT THE REGULATORY AGENCIES IN ARKANSAS LACK AUTHORITY TO PREVENT FURTHER CAMAGES AND ILLEGAL OPERATIONS BY THE OPERATOR. THIS IS NOT THE CASE AND THE ARKANSAS WATER AND AIR POLLUTION ACT GIVES AUTHORITY AT SEVERAL LEVELS TO REQUIRE CLEANUP OF THESE ILLEGAL ACTIVITIES AND TO PREVENT FUTURE OCCURRENCES						

TX21 DRLG Y ESENJAY SURF WTR MUD Y ILLEGAL DISCHARGE OF MUD RESULTED IN OPERATOR FINE AND CLEANING SITE

THIS CASE STATES THAT THE OPERATOR BREACHED A DRILLING PIT DIKE ALLOWING MUD TO DISCHARGE INTO HARDY SANDY CREEK. THIS DISCHARGE TO WATERS OF THE UNITED STATES WAS ILLEGAL AND THE TEXAS RAILROAD COMMISSION FINED THE OPERATOR $ 10,000. ADDITIONAL REGULATIONS WOULD NOT HAVE PREVENTED THIS POLLUTION INCIDENT.

TX22 DRLG Y TXO PROD SURF WTR MUD Y SURFACE DISCHARGE OF DRILLING MUD, OPERATOR FINED

THIS CASE ALLEGES THAT THE OPERATOR BROKE A DRILLING PIT DIKE AND ALLOWED DRILLING FLUIDS TO FLOW OFFSITE INTO A STOCK TANK. AS A RESULT, FISH IN THE TANK WERE KILLED. THE CASE ALLEGES THE FISH FATALITIES WERE CAUSED BY HIGH LEVELS OF METAL IN THE MUD, HOWEVER, THIS REPORT IS SPECULATIVE AS LAB RESULTS SHOWED LOW METAL CONCENTRATIONS IN THE WATER. LABORATORY TESTS SUGGEST OXYGEN DEPLETION WAS THE MOST LIKELY CAUSE. IN ADDITION, EXTREMELY COLD WEATHER OCCURRED DURING THIS TIME THAT COULD HAVE COMPUNDED OR EVEN CAUSED THE PROBLEM. THIS TYPE POLLUTION INCIDENT IS ADDRESSED BY TEXAS REGULATIONS AS THE OPERATOR WAS FINED AND THE LANDOWNER COMPENSATED FOR DAMAGES.

WY03 PROD Y ALTEX OIL SURF/GND WTR & SOIL PROD WTR Y ILLEGAL DISCHARGE OF PRODUCED WATERS

ALTEX OIL PURCHASED THE PROPERTY IN THIS CASE IN 1984 AND UPON INSPECTION OF THE FACILITIES FOLLOWING A COMPLAINT TO THE STATE CEASED SURFACE DISCHARGE OF PRODUCED WATER WHICH WAS IN VIOLATION OF STATE REGULATIONS.

WY05 PROD Y MARATHON SURF/GND WTR & SOIL CHEMICAL Y ILLEGAL DISCHARGE OF CHEMICALS

THIS CASE STATES THAT THE OPERATOR DURING CLEANUP OF A DRUM STORAGE AREA PUNCTURED DRUMS AND ALLOWED CHEMICALS TO DRAIN TO A DITCH. THE CASE DESCRIPTION IS INCORRECT. THE OPERATOR THINKING THAT THE DRUMS HAD TO BE COMPLETELY EMPTY BEFORE TRANSPORTING THEM OFFSITE TURNED THE DRUMS UPSIDE DOWN AND DRAINED APPROXIMATELY 420 GALLONW INTO THE DITCH. HOWEVER, THE EMPTYING OF CHEMICAL INTO A DITCH WAS ILLEGAL. IN ADDITION IT WAS DISCOVERED THAT TWO TRANSFORMERS WERE LEAKING PCB CONTAMINATED TRANSFORMER OIL AT THE SITE. THE CHEMICALS AND PCD CONTAMINATED OILS WERE REMOVED AND THE WASTE SOIL DISPOSED AT A LICENSED DISPOSAL FACILITY. GROUNDWATER MONITORING WELLS SHOWED NO CONTAMINATION OCCURRED. THE OPERATOR WAS ASSESSED A FINE FOR VIOLATIONS OF STATE REGULATIONS. ADDITIONAL REGULATIONS WOULD NOT PREVENT THIS TYPE POLLUTION INCIDENT.

WV18 DISCHARGE Y Y Y ALLEGHANY LANDS WURF/GND WTR & SOIL PROD WTR Y ILLEGAL WASTE DISCHARGE INTO BEVERLIN FORK

THE OPERATOR DISCHARED OILFIELD WASTES FROM DRILLING PITS INTO A DITCH RUNNING INTO BEVERLIN FORK. THE OPERATOR ALLOWED THE LANDOWNER'S LIVESTOCK TO DRINK FROM THE PITS. THE REPORT STATES

THAT THE LIVESTOCK WERE POISONED CAUSING NUMEROUS PROBLEMS INCLUDING DEATH. THIS WAS A PRACTICE BEGUN IN 1979 WITH THE CONSENT OF BOTH THE LANDOWNER AND OPERATOR. THIS CASE CENTERS AROUND THE SUITABILITY OF THE LIQUIDS FOR LIVESTOCK CONSUMPTION, NOT DISCHARGE OFFSITE TO WATERS OF THE U.S. OR LEACHING TO GROUNDWATER. HOWEVER, STATE REGULATIONS ARE IN PLACE FOR DISCHARGES TO THE SURFACE OR GROUNDWATER.
THE OPERATOR PAID A $ 39,000 FINE PLUS
INTEREST AND COSTS. SUFFICIENT REGULATIONS ARE IN PLACE TO DEAL WITH THESE TYPE OCCURRENCES.

LA15 PROD Y SUN SURF WTR MUD/OIL Y ILLEGAL DISCHARGE OF PRODUCED WATER INTO FRESHWATER MARSH

THIS CASE STATES THE OPERATOR DISCHARGED SALTWATER INTO THE ADJACENT MARSH FROM A FACILITY PIT AND TANK BATTERY RING LEVEE. THE DISCHARGE FROM THE RING LEVEE WOULD BE LEGAL IF USED UNDER SPCC PLANS. HOWEVER, SALT WATER CANNOT BE DRAINED FROM RING LEVEES UNDER SPCC PLANS AND THEREFORE THIS WAS A VIOLATION AND A NOTICE OF VIOLATION WAS ISSUED AND THE PROBLEM CORRECTED.

AR10 DISCHARGE Y J.BEEBE SURF/GND WTR & SOIL PROD WTR Y USE OF ILLEGAL SALTWATER PITS FLOWING INTO SMACKOVER CREEK

THIS CASE STATES THAT SALTWATER WAS DISCHARGED FROM A SALTWATER DISPOSAL WELL INTO SMACKOVER CREEK. THIS DISCHARGE WAS CORRECTED BY THE OPERATOR BUT A LATER INVESTIGATION FOUND THAT ADDITIONAL DISCHARGES WERE COMING FORM FACILITY PITS. TWO PITS WERE DISCHARGING IN VIOLATION OF ARKANSAS REGULATIONS. A NOTICE OF VIOLATION WAS ISSUED BY THE ADPC AND CIVIL PENALTY ASSESSED.

WV20 DISCHARGE Y Y MARRIETTA ROY SURF WTR MUD Y ILLEGAL DISCHARGE OF DRILLING MUD TO STILLWELL CREEK

THE OPERATOR WILLFULLY SYPHONED FLUIDS FROM THE DRILLING PIT INTO STILLWELL CREEK WITHOUT A PERMIT. THIS DISCHARGE IN TO THE CREEK WAS A DIRECT VIOLATION OF WEST VIRGINIA CODE 20-5A-19A AND THE OPERATOR WAS FINED.

PA09 PROD Y Y NOT LIST SURF/GND WTR & SOIL MUD/PROD WTR/OIL Y DAMAGE FROM OLD PRACTICES AND SPILLS

THIS CASE REPRESENTS THE OLDEST COMMERCIAL OIL PRODUCING REGION IN THE WORLD. CHRONIC LOW LEVEL RELEASES HAVE OCCURRED IN THIS AREA FOR YEARS. THESE DISCHARGES SHOULD NOT BE CHARACTERIZED AS ILLEGAL DUMPING BECAUSE THE LEAKS OCCUR AS A RESULT OF OLD, PAST PRACTICES AND NOT BECAUSE OF DUMPING BY IRRESPOSIBLE OPERATORS. CURRENTLY, LEAKS INTO STREAMS ARE PROHIBITED BY STATE AND FEDERAL REGULATIONS AND THESE AGENCIES ARE ENFORCING THEIR REGULATIONS. IN ADDITION, IF DISCHARGES OF OIL ARE PURPOSEFULLY OCCURRING THESE ARE REGULATED BY EPA'S SPCC REGULATIONS UNDER THE CLEAN WATER ACT. ENFORCEMENT OF VIOLATIONS IS THE RESPONSIBILITY OF THE U.S. COAST GUARD WHO MUST CORRECT AND LEVY FINES FOR VIOLATIONS.

PRODUCED WATER AND OIL FIELD WASTE PIT CONTENTS LEACHING INTO GROUND WATER

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIN RESOURCE	CONTAIN WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
NM02	PROD		Y				Y	STUDY	NONE	NONE		STUDY ON USE OF SMALL SW PITS BANNED IN 1985 IN THE SAN JUAN BASIN

THE EPA CONTRACTOR WRITEUP OF THIS CASE IS ERRONEOUS. NO VIOLATION OF STATE GROUNDWATER STANDARDS WERE FOUND (SEE API AND NEW MEXICO COMMENTS IN DOCKET). IN ADDITION, PRESENT REGULATIONS REQUIRE DISPOSAL PITS TO BE PERMITTED AND LIMITED TO 5 BARRELS A DAY IN THE SAN JUAN BASIN AREA OF NEW MEXICO. FURTHER, THE STATEMENT THERE ARE OVER 20,000 UNLINED PRODUCED WATER DISPOSAL PITS IN NEW MEXICO HAS BEEN REFUTED IN IN A JUNE 15, 1987 LETTER FROM GOVERNOR CARRUTHERS TO J. WINSTON PORTER. GOVERNOR CARRUTHERS IN HIS LETTER STATES "UNLINED PITS IN FRESH WATER AREAS IN SOUTHEAST NEW MEXICO WERE BANNED BEGINNING IN 1956, WITH A GENERAL PROHIBITION ADOPTED IN 1967."

NM05	COMMERCIAL SITE		Y	Y	Y			BLM	GND WTR	MUD/PROD WTR	Y	PAST DISPOSAL SITE USING UNLINED PITS CLOSED IN 1985

PRESENT REGULATIONS PROHIBIT UNLINED DISPOSAL PITS. CURRENT REGULATIONS REQUIRE LINED PITS AND MONITORING WELLS WITH LEAK DETECTION FOR COMMERCIAL DISPOSAL PITS SUCH AS THE ONE REFERENCED IN THIS CASE.

LA67	COMMERCIAL SITE		Y		Y			PAB CO	GND WTR	PROD WASTE	Y	ILLEGAL USE OF OIL SKIMMING PITS, STATE SHUT DOWN OPERATIONS

PAB WAS OPERATING WHEN LOUISIANA PROMULGATED ITS FIRST COMMERCIAL OIL FIELD FACILITY REGULATIONS. PAB EITHER COULD NOT OR WOULD NOT UPGRADE TO MEET THE NEW REGULATIONS AND WAS SHUT DOWN AND SEALED BY LOUISIANA'S OFFICE OF CONSERVATION. FOR ADDITIONAL DOCUMENTATION, SEE LETTER IN DOCKET FROM LA. OFFICE OF CONSERVATION TO R.M. HALL OF EPA DATED APRIL 16, 1987

ALLOWABLE DISCHARGE OF WATER INTO SURFACE STREAMS AND EPHEMAL STREAMS

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIN RESOURCE	CONTAIN WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
WY07	PROD	Y				Y		UNION	NONE	PROD WTR		STUDY ON THE IMPACTS OF LOW SALINITY PRODUCED WATER DISCHARGES

THIS CASE REPRESENTS A STUDY ON THE IMPACT TO SURFACE STREAMS OF DISCHARGES THAT ARE PERMITTED UNDER THE CLEAN WATER ACT'S NPDES PROGRAM THAT IS ADMINISTERED BY THE EPA. SPECIFICALLY, THESE DISCHARGES ARE ALLOWED UNDER THE AGRICULTURAL AND WILDLIFE WATER USE SUBCATEGORY AS DEFINED IN 40CFR PART 435 SUBPART E. THESE DISCHARGED WATERS SERVE A BENEFICIAL USE IN THE ARID WESTERN U.S. AND ARE THE MAJOR SOURCE OF USABLE WATER TO MANY LANDOWNERS. THE PROTECTION OF THESE STREAMS FROM HYDROCARBON AND SALT CONTAMINATION IS ADEQUATELY ADDRESSED BY WYOMING DEPT. OF ENVIRONMENTAL QUALITY REGULATIONS THAT LIMITS THE CONSTITUENT CONCENTRATIONS BY OPERATORS.

CA21	PROD							NONE	STUDY	PROD WTR		STUDY TO INVESTIGATE LEGAL USE OF REGULATED PERCOLATION PITS

THIS CASE REFERENCES TWO STUDIES ON THE IMPACT ON GROUNDWATER OF THE DISCHARGE OF PRODUCED WATER INTO EPHEMERAL STREAMS THAT FEED PERCOLATION AND EVAPORATION PITS IN CALIFORNIA. THIS PRACTICE IS UNIQUE TO CALIFORNIA'S DESERT AREAS BECAUSE OF THE LACK OF GROUNDWATER RESOURCES. ONE STUDY CONCLUDES THAT THE PITS HAVE CAUSED GROUNDWATER CONTAMINATION ON THE BASIS OF ASSUMPTIONS AND IN SPITE OF A LACK OF DATA. THE SECOND STUDY SHOWS THE 1400 SQUARE MILE AREA IN QUESTION TO BE DESERT-LIKE AND UNDERLAIN WITH NON POTABLE GROUNDWATER RESERVOIRS. IT IS PRECISELY THIS LO POTENTIAL FOR ENVIRONMENTAL OR HUMAN HEALTH DAMAGE THAT HAS CAUSED THE STATE OF CALIFORNIA TO ALLOW THIS PRACTICE. EPA AND THE STATE OF CALIFORNIA REGIONAL WATER QUALITY BOARD ARE PRESENTLY DECIDING WHETHER TO PROMULGATE ADDITIONAL PERMIT REQUIREMENTS UNDER THE CLEAN WATER ACT'S NPDES PROGRAM.

CA08	PROD							NOT LIST	SURF/GND WTR & SOIL	PROD WTR	Y	EROSION OF PERCOLATION PIT DIKE ALLOWED BREACH AND DISCHARGE

SAME ISSUE AS DESCRIBED IN CASE CA21 DEALING WITH USE OF PERCOLATION PIT UNIQUE TO CALIFORNIA. THIS CASE STATES A DIVERSION ERODED ALLOWING RELEASE OF WATERS FROM A PERCOLATION PIT. RELEASE OF THE WATERS WAS A VIOLATION OF CALIFORNIA REGULATIONS AND THE OPERATORS WERE FINED. THE NEED FOR ADDITIONAL PERMIT CONDITIONS UNDER THE CLEAN WATER ACT'S NPDES PROGRAM ARE BEING DETERMINED BY THE EPA AND STATE OF CALIFORNIA.

PA02 DISCHARGE Y Y STUDY SURF WTR PROD WTR STUDY ON IMPACT OF SURFACE WATER DISCHARGES IN VIOLATION OF STATE REGS

THIS CASE REFERENCES A STUDY CONDUCTED BY THE U.S. FISH AND WILDLIFE SERVICE TO DETERMINE CHANGES IN AQUATIC LIFE FROM 1982-1985 RESULTING FROM SURFACE DISCHARGES OF OIL FIELD WASTE. SPECIFIC STATE STANDARDS CONCERNING THESE DISCHARGES WERE ESTABLISHED IN 1985. PRESENTLY, DISCHARGES OF PRODUCED WATERS ARE ALLOWED ONLY VIA THE NPDES PERMIT SYSTEM AS IS REQUIRED BY FEDERAL AND STATE LAW. THESE PERMITS ARE ISSUED WITH REGARD TO WATER QUALITY STANDARDS DESIGNED TO PROTECT AQUATIC LIFE. THUS, THE STATE HAS USED ITS AUTHORITY UNDER THE EXISTING REGULATORY FRAMEWORK TO DEVELOP A MECHANISM TO ADDRESS THE ISSUE. IF ADDITIONAL REGULATION OR ENFORCEMENT WERE PROVEN TO BE NECESSARY THESE STEPS COULD BE TAKEN BY EPA OR PA. UNDER THE CLEAN WATER ACT.

GROUNDWATER CONTAMINATION FROM UNDERGROUND INJECTION

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND- ING CASE	VIOLATES CURR REGS	UNSUB- STAN- TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIN RESOURCE	CONTAIN WASTE	ADMIN/ ENFORCE- MENT ACTION	EPA CASE DESCRIPTION
AR12	UIC				Y			J. MCCLAIN	SURF/GND WTR & SOIL	PROD WTR	Y	ILLEGAL NONPERMITTED DISPOSAL WELL AND USE OF ILLEGAL SW DISPOSAL PITS

ANNULAR INJECTION AND INJECTION WITH OUT A PERMIT IS A VIOLATION OF UNDERGROUND INJECTION CONTROL REGULATIONS. VIOLATION OF EMERGENCY PIT USE FOR CONTINUOUS PRODUCED WASTE CONTAINMENT, HOWEVER IS THE MOST PROBABLE CAUSE OF THIS DAMAGE CASE. VIOLATIONS HAVE BEEN CORRECTED AS A RESULT OF STATE ACTIONS. THE STATE ALSO REINSPECTED THE SITE WHICH HAS BEEN FOUND TO BE IN COMPLIANCE.

OH38	UIC	Y			Y		Y	NOT LIST	GND WTR	PROD WTR	Y	1976 DAMAGE TO FRESH WATER WELLS PRIOR TO UIC REGULATIONS

CONTAMINATION EXISTED PRIOR TO UIC REGULATIONS WHICH PROVIDE THE REGULATORY AUTHORITY TO REQUIRE INTEGRITY OF INJECTION WELLS. OHIO IS THE ONLY STATE TO ALLOW ANNULAR INJECTION OF PRODUCED WATER AND HAS ENACTED SPECIAL REQUIREMENT TO CONTROL THE PLACEMENT OF FLUIDS AND CORROSION OF CASINGS. THIS WELL PROBABLY WAS DAMAGED BEFORE ENACTMENT OF THESE REGULATIONS AND COULD NOT PASS THE CURRENT CRITERIA FOR MECHANICAL INTEGRITY

NM01	UIC	Y			Y	Y	Y	TEXACO	GND WTR	PROD WTR		DAMAGE FROM OLD SALTWATER PITS AND NOT INJECTION WELL STILL IN SERVICE

THIS CASE ALLEGES THAT SALTWATER IS CONTAMINATING A USDW FROM AN INJECTION WELL. THE WELL HAS BEEN TESTED AND FOUND TO BE IN COMPLIANCE WITH NEW MEXICO UIC REGULATIONS. THE ASSERTION THAT THE WELL WOULD NOT PASS THE TEXAS MIT TEST IS NOT SUPPORTED BY FACTS AND IS SPECULATIVE. SUBSEQUENT PRESSURE TESTS HAVE FURTHER DEMONSTRATED THAT THE WELL IS NOT CONTAMINATING GROUNDWATER AND IT IS STILL IN SERVICE. IT APPEARS SALTWATER PITS USED IN THE PAST AND NOW CLOSED WERE THE PROBLEM. CURRENT REGULATIONS PROHIBIT USE OF UNLINED, UNPERMITTED SALT WATER PITS.

KS06	UIC				Y			NOT LIST	GND WTR	PROD WTR	Y	LEAKING INJECTION WELL VIOLATING UIC REGULATIONS DAMAGED FW WELL

THIS INJECTION WELL PROBLEM OCCURRED IN 1981. THE OPERATOR INJECTED WATER INTO A WELL WITH HOLES IN THE CASING AND DAMAGED GROUNDWATER. THIS VIOLATED THE PRESENT KANSAS REGULATION FOR MECHANICAL INTEGRITY IN UNDERGROUND INJECTION. KANSAS OBTAINED PRIMACY FROM EPA TO OPERATE ITS UIC PROGRAM IN 1984. THE PRESENT PROGRAM WOULD HAVE UNCOVERED THIS PROBLEM AND REQUIRED THE OPERATOR TO CORRECT IT.

OK06	UIC	Y	NOT LIST	SURF/GND WTR & SOIL	PROD WTR Y	INJECTION WELL THOUGHT TO ENDANGER FRESH WATER

IN THIS CASE SURFACE WATER WAS FOUND TO BE CONTAMINATED BY SALTWATER. A SALTWATER INJECTION WELL WAS WORKED OVER AND NOW MEETS UIC REQUIREMENTS WITH MIT TESTS AND TRACER LOGS INDICATING THE INJECTION WELL IS NOT A CURRENT SOURCE OF CONTAMINATION. CONTAMINATION OF SURFACE WATER HAS CONTINUED AND IS NOW SUSPECTED BY THE OPERATOR TO BE A RESULT OF USE OF PAST SURFACE PITS AND DISCHARGES IN THIS OLD PRODUCING AREA. EVEN IF THE PROBLEM WAS SOLELY THE FAULT OF THE INJECTION WELL, CURRENT UIC REGULATIONS WOULD HAVE DISCOVERED IT AND REQUIRED WORKING OVER THE INJECTION WELL. CURRENT REGULATIONS WOULD ALSO HAVE PROHIBITED USE OF SALT WATER DISPOSAL PITS.

MI06	UIC	Y	NOT LIST	GND WTR	PROD WTR Y	FRESH WATER DAMAGE FROM WELL IN VIOLATION OF EPA UIC REGULATIONS

CONTAMINATION FROM IMPROPERLY PLUGGED WELLS

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
KS03	MISC	Y	Y		Y			WESTERN DRLG	GND WTR	PROD WTR		DAMAGE FROM DRILLING RESERVE PIT

THE KANSAS DEPARTMENT OF HEALTH AND ENVIRONMENT HAD RESPONSIBILITY FOR DRILLING PITS WHEN THIS WELL WAS DRILLED. SINCE THEN, AUTHORITY WAS TRANSFERRED TO THE KCC ON JULY 1, 1987. KCC HAS ADOPTED REGULATIONS REQUIRING ALL PITS BE PERMITTED

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
KS14	MISC		Y		Y			GULF	SURF/GND WTR & SOIL	PROD WTR		1961 DAMAGE CASE FROM PRIOR OPERATIONS

DAMAGE NOT PROVEN TO BE FROM P&A'D OIL WELLS BUT IS PROBABLY FROM OLD INJECTION PRACTICES. CURRENT UIC REGULATIONS WOULD HAVE PREVENTED DAMAGE THROUGH THE "AREA OF REVIEW" AND MECHANICAL INTEGRITY TESTING REGULATIONS REQUIRED UNDER THE SAFE DRINKING WATER ACT. THESE REGULATIONS REQUIRE TESTING INJECTION WELLS FOR LEAKS AND ADEQUATE PLUGGING OF ALL OLD WELLS BEFORE INITIATION OF INJECTION.

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
TX05	MISC	Y			Y			NOT LIST	GND WTR	SALT WTR	Y	1984 WELLS LEAKING FROM COLEMAN FORMATION REPLUGGED BY TEXAS

THREE WELLS WERE IMPROPERLY PLUGGED BECAUSE TOP CEMENT PLUGS WERE NOT SET BY THE OPERATOR. WHEN SALTWATER FROM FROM A NATURALLY PRESSURED SALT WATER AQUIFER WAS NOTICED BY THE LANDOWNER THE TEXAS RAILROAD COMMISSION REPLUGGED THE THREE WELLS. TEXAS RAILROAD COMMISSION RULES REQUIRE CEMENTING IN ABANDONED WELLS ACROSS ZONES BELOW FRESH WATER AND THEIR FIELD INSPECTORS ARE RESPONSIBLE FOR REQUIRING PROPER ABANDONMENT OR THE STATE CONDUCTING PROPER ABANDONMENT.

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
TX11	MISC	Y	Y			Y	Y	UNKNOWN	GND WTR	SALT WTR		UNKNOWN SOURCE OF SALT SEEPS IN WEST TEXAS

NO IMPROPERLY ABANDONED WELLS WERE SITED AS A LIKELY SOURCE OF DAMAGE TO SOIL AND GROUNDWATER IN THIS AREA AND THE SOURCE OF DAMAGE IS NOT PROVEN. COMMENTS FROM THE TEXAS RAILROAD COMMISSION STATE THAT THE SOIL AND GROUNDWATER ARE PROBABLY CONTAMINATED AS A RESULT OF THE TERRACING AND FERTILIZING OF THE PROPERTY.

TX15 MISC Y Y KEETON EXPL GND WTR SALT WTR Y WATER WELL DAMAGED FROM ILLEGAL OPERATIONS

KEETON EXPLORATION OPERATED A LEASE WITH ILLEGAL SURFACE DISCHARGES THAT VIOLATED TEXAS RAILROAD COMMISSION RULES 8, 14 AND 20. THE FIELD WAS ORDERED CLOSED AND THE OPERATOR FINED. IN CLOSING THE FIELD THE RAILROAD COMMISSION PROPERLY PLUGGED 5 WELLS. TEXAS REGULATIONS REQUIRE PLACING CEMENT PLUGS ACROSS OLD PRODUCING FORMATIONS AND BELOW THE BASE OF GROUNDWATER TO PREVENT CONTAMINATION. IF AN OPERATOR DOES NOT COMPLY TEXAS WILL PLUG THE WELLS PROPERLY ITSELF.

LA65 MISC Y Y Y COQUINA SURF/GND SALT WTR ALLEGED IRRIGATION WELL AND SURFACE SW DAMAGE FROM PAST OIL PROD
HUGHES WTR
JUSTIS-MEARS
BELL
GRUBB
BASS

SOURCE OF DAMAGE IS NOT PROVEN AND THIS CASE IS UNDER INVESTIGATION BY THE LOUISIANA OFFICE PF CONSERVATION. DAMAGE IS PROBABLY FROM NON-CURRENT OIL FIELD PRACTICES ALTHOUGH THIS CAN NOT BE ESTABLISHED UNTIL THE INVESTIGATION IS COMPLETED. IF FROM PAST PRACTICES, CURRENT REGULATIONS WOULD HOWEVER PREVENT THESE TYPE DAMAGES (UIC, SDWA, DRILLING AND PLUGGING REQUIREMENTS)

KS03 MISC Y WESTERN DRLG NONE NONE ALLEGED DAMAGE FROM P&A'D WELL

AFTER INVESTIGATION BY THE KCC, IT WAS FOUND NO DAMAGE HAD BEEN CAUSED BY THIS WELL. THE INVESTIGATION SHOWED THAT ALTHOUGH THE TOP CEMENT PLUG WAS LOW THAT IT WAS STILL EFFECTIVE IN PREVENTING GROUND WATER CONTAMINATION. THE KCC FINDING WAS DOCUMENTED IN COURT CASE AWARDING DAMAGES NOT FOR THE ABANDONED WELL BUT FOR AN ABANDONED RESERVE PIT.

DAMAGE RELATED TO POOR LEASE MAINTENANCE

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIN RESOURCE	CONTAIN WASTE	ADMIN/ ENFORCE-MENT ACTION	CASE DESCRIPTION
KS01	PROD				Y		Y	TEMPLE	WTR/SOIL	SALTWATER	Y	HABITUAL VIOLATOR OF REGULATIONS BANNED FROM OPERATIONS IN KANSAS

THIS CASE DOES NOT DEMONSTRATE A NEED FOR ADDITIONAL REGULATION
OPERATOR WAS A HABITUAL VIOLATOR (39 VIOLATIONS IN TWO YEARS) OF REGULATIONS RESULTING IN NUMEROUS VIOLATIONS OF STATE RULES. THE KCC ASSESSED A PENALTY, REVOKED THE OPERATORS LICENSE AND PROHIBITED FURTHER OPERATIONS ON THE LEASE AND WITHIN KANSAS BY THE OPERATOR WITHOUT PUBLIC NOTICE AND HEARING.
THE " LEASE MAINTENANCE" SECTION OF KANSAS REGULATIONS WERE ISSUED MAY 13, 1987 REQUIRING PERMITS FOR ALL PITS (DRILLING AND PRODUCING), EMPTYING OF EMERGENCY PITS WITHIN 48 HOURS, NOTIFICATION OF SPILLS WITHIN 24 HOURS AND SPECIFIC PENALTIES APPLICABLE FOR EACH VIOLATION. IN ADDITION KCC HAS AUTHORITY TO SHUTDOWN AN OPERATOR TO ENFORCE ITS REGULATIONS.
FURTHER DOCUMENTATION IS INCLUDED IN K.A.R. 82-3-600 THROUGH 603.

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIN RESOURCE	CONTAIN WASTE	ADMIN/ ENFORCE-MENT ACTION	CASE DESCRIPTION
KS08	PROD				Y			HARR	SOIL	SALT WATER	Y	ILLEGAL USE OF SALTWATER PITS, OPERATION ORDERED CLOSED BY KCC

THIS CASE DOES NOT DEMONSTRATE A NEED FOR ADDITIONAL REGULATION.
AN UNPERMITTED EMERGENCY POND WAS FOUND TO BE LEAKING SALTWATER. THE OPERATOR WAS ORDERED TO CORRECT THE SITUATION BY LINING THE POND AND SECURING A PERMIT. THE OPERATOR DID NOT COMPLY AND AN ORDER TO CLOSE THE POND WAS ISSUED BY KDHE.
THE SITE HAS BEEN CLOSED
FOR ADDITIONAL DOCUMENTATION SEE COMMENTS ON KS01 PERTAINING TO KCC "LEASE MAINTENANCE" REGULATIONS CONTAINED IN K.A.R. 82-3-600 THROUGH 603.

DISCHARGE OF PRODUCED WATER AND DRILLING MUD INTO BAYS AND ESTUARIES OF THE TEXAS GULF COAST

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
TX55	DISCHARGE	Y				Y	Y	NOT LISTED	FISH	SALT WATER		ALLEGED SEDIMENTS FROM NPDES DISCHARGE ENDANGERING FISH

THIS CASE DOES NOT DEMONSTRATE A NEED FOR ADDITIONAL REGULATION
THIS IS A DISCHARGE SUBJECT TO THE NPDES PROGRAM UNDER THE CWA ADMINISTERED BY EPA. ALTHOUGH DUE TO THE FAILURE OF EPA TO ISSUE PERMITS FOR THIS TYPE DISCHARGE, THE TEXAS RAILROAD COMMISSION HAS ESTABLISHED A PERMIT PROGRAM TO ENSURE DISCHARGES DO NOT ENDANGER HUMAN HEALTH OR THE ENVIRONMENT. NO REFERENCES ARE CITED IN THIS CASE TO DETERMINE IF POLLUTION AND ENDANGERMENT OF FISH IS THE RESULT OF OIL FIELD DISCHARGES OR DISCHARGES OF THE SHIPPING AND PETROCHEMICAL INDUSTRIES OR DISCHARGE OF NONINDUSTRIAL WASTES.
THERE ARE MANY SOURCES OF DISCHARGE IN THE HOUSTON SHIP CHANNEL OTHER THAN OIL AND GAS PRODUCTION OPERATIONS.

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
TX31	DISCHARGE	Y				Y	Y	NOT LIST	FISH	SALT WATER		ALLEGED ENDANGERMENT TO FISH FROM NPDES DISCHARGE

THIS CASE DOES NOT DEMONSTRATE A NEED FOR ADDITIONAL REGULATION
THIS DISCHARGE IS PERMITTED BY THE TEXAS RAILROAD COMMISSION
NPDES PROVISIONS OF THE SAFE DRINKING WATER ACT. TEXAS REQUIRES PERMITS FOR DISCHARGES THAT WILL NOT DEGRADE THE QUALITY OF THE RECEIVING WATER BODY. THE STUDY REFERENCED DID NOT RECOGNIZE THE MIXING THAT OCCURS BETWEEN THE DISCHARGED AND RECEIVING WATERS. OTHER STUDIES SHOWN NO ADVERSE EFFECTS FROM THESE DISCHARGES.

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
TX29	DISCHARGE	Y			Y			TEXACO/AMOCO	SURF WTR	SALT WATER	Y	TEXAS RAILROAD COMMISSION STOPPED DISCHARGE TO BAFFIN BAY

THIS CASE DOES NOT DEMONSTRATE A NEED FOR ADDITIONAL REGULATION.
UPON REVIEW, THE TEXAS RAILROAD COMMISSION REVOKED THIS DISCHARGE PERMIT DUE TO CONCERNS THE DISCHARGE WAS ADVERSLY EFFECTING THE QUALITY OF THE RECEIVING WATERS.
THIS DISCHARGE WAS ALSO SUBJECT TO REGULATION OF EPA UNDER NPDES PROVISIONS OF THE CLEAN WATER ACT.

DAMAGE RELATED TO ARTIC PRODUCTION OPERATIONS

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
AK10	SALVAGE OPERATION	Y			Y		Y	NSSI	SURF WTR	CHEMICALS	Y	ILLEGAL AND UNREPORTED CHEMICAL SPILLS

THIS CASE REFERS TO THE IMPROPER AND ILLEGAL STORAGE AND HANDLING OF USED DRUMS BY A COMMERCIAL SALVAGE COMPANY. THE ADEC AND DNR ACTED TO QUICKLY DEVELOP AND IMPLEMENT A CLEAN UP PLAN WITH THE SALVAGE COMPANY AND WITH NORTH SLOPE OPERATORS. ISSUES OF THIS TYPE ARE SPECIFICALLY ADDRESSED IN ADEC SPILL CLEANUP AND NOTIFICATION REQUIREMENTS DOCUMENTED IN 18 AAC 75.080. NOTE THAT AFTER CLEANUP, A MONITORING PROGRAM OF ADJACENT TUNDRA AREAS AND PONDS WAS UNDERTAKEN. TEST SHOWED THAT WATER AND TUNDRA WERE FREE OF CONTAMINCATION.

DAMAGE TO WATER WELLS FOLLOWING FRACTURING OPERATIONS ON PRODUCING WELLS

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
WV17	PROD	Y						KAISER GAS	GNDWTR	FRAC FLUID		DURING WORKOVER OF GAS WELL, FRACTURING FLUID REACHED A WATER WELL
PA08	DRLG & PROD		Y		Y			NORWESCO	GND WTR	PROD WTR	Y	DAMAGE FROM ILLEGAL OPERATIONS

WV17: THIS CASE IS NOT A WASTE BUT PRODUCTION OPERATIONS ISSUE. THE DAMAGE HERE RESULTS FROM AN ACCIDENT OR MALFUNCTION OF THE FRACTURING PROCESS. IN THIS PROCESS, PRODUCING WELLS HAVE SAND LADEN FLUIDS PUMPED INTO THE PRODUCING FORMATIONS AT RATES THAT CREATE CRACKS THAT ARE PROPPED OPEN TO ALLOW FLOW OF OIL OR GAS TO THE WELLBORE. THE PROCESS REQUIRES THE FRACTURES TO BE CREATED TO BE LIMITED TO THE PRODUCING FORMATION. IF THEY ARE NOT AS IS THE APPARENT CASE HERE OIL AND GAS ARE LOST FROM THE RESERVOIR AND ARE UNRECOVERABLE.

PA08: THIS DAMAGE CASE IS NOT THE RESULT OF DAMAGE AFTER FRACTURING OPERATIONS BUT RATHER ILLEGAL OPERATIONS BY A PRODUCTION OPERATOR. BOTH THE PA. DEPARTMENT OF ENVIRONMENTAL RESOURCES AND PA. FISH COMMISSION CITED NORWESCO FOR ILLEGAL OPERATIONS AND DISCHARGE OF PRODUCED WATERS AT LEAST 19 TIMES. THE OPERATOR SOUGHT BANKRUPTCY PROTECTION BUT WAS STILL REQUIRED TO MAKE A CASH SETTLEMENT TO REPLACE THE GROUND WATER RESOURCES HE HAD DAMAGED.

DAMAGE RELATED TO PRODUCTION OPERATIONS SPILLS

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIN RESOURCE	CONTAIN WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
AK09	OIL SPILL	Y				Y		NOT LIST	SURF WTR	OIL		ALLEGED OIL SPILL FROM OIL WELL PLUGGED PRIOR TO 1973-75 STUDY
MI05	PROD					Y		TROPE	GND WTR	PROD WTR		DAMAGE FROM SPILLS FROM PRODUCTION FACILITIES

AK09: THIS IS AN OIL SPILL INCIDENT. NO SAMPLING WAS RECORDED IN CONNECTION WITH THE OIL SPILL INCIDENT, AND MUCH OF THE DAMAGE CASE TEXT IS ASSUMPTION AND SPECULATION. NUMEROUS FEDERAL AND STATE REGULATIONS REGARDING POLLUTION CONTROL EXIST (SEC. 311 CLEAN WATER ACT), AND MOST HAVE BEEN IMPLEMENTED SINCE THE WRITING OF THE FWS REPORT OVER TEN YEARS AGO. ADEC REGULATION 18 AAC 75.080 REQUIRES OIL SPILL NOTIFICATION AND CLEANUP.

MI05: THIS CASE IN INCORRECTLY REFERRED TO AS CAUSED BY IMPROPER RESERVE OR DISPOSAL PITS. THE CASE DESCRIPTION ACTUALLY INDICATES THAT THE SOURCE OF THE GROUNDWATER CONTAMINATION IS BRINE STORAGE TANKS AND CRUDE OIL SEPARATOR FACILITIES. AS IS THE NORMAL CASE IN MICHIGAN, THE GEOLOGICAL SURVEY INVESTIGATED THOROUGHLY AND USED STIFF DIAGRAMS TO CONFIRM THE SIMILARITY OF THE CONSTITUENTS OF THE FORMATION PRODUCED WATER AND THE CHLORIDE CONTAMINATION OF THE AFFECTED WATER WELLS. THIS INDICATES THE SOURCE TO BE LEAKS OR SPILLS OF PRODUCED WATER FROM THE PRODUCTION FACILITIES. MICHIGAN REGULATIONS COVER SUCH SPILLS. MICHIGAN COMPILED LAWS, SECTION 323.1 AND 323.6, AS WELL DEPARTMENT OF NATURAL RESOURCES WATER RESOURCE COMMISSION GENERAL RULE 323.1164 COVER RELEASES OF OIL, SALT OR OTHER POLLUTING MATERIAL. IMMEDIATE NOTIFICATION AND A SUBSEQUENT REPORT DEALING WITH THE CAUSE, DISCOVERY, AND CLEANUP

GROUNDWATER CONTAMINATION FROM IMPROPERLY COMPLETED WELLS

EPA CASE NO.	EPA DAMAGE CATAGORY	NON RCRA ISSUE	NON CURRNT PRACTICE	PEND-ING CASE	VIOLATES CURR REGS	UNSUB-STAN-TIATED	MAJOR FACTS DISPUTED	CO. NAME	CONTAIM RESOURCE	CONTAIM WASTE	ADMIN/ ENFORCE-MENT ACTION	EPA CASE DESCRIPTION
NM03	PROD	Y			Y			MANANA	GND WTR	OIL		ALLEGED OIL CONTAMINATION OF GND WTR BY PRODUCING WELL
NM04	PROD		Y		Y			NOT LIST	GND WTR	PROD WTR/		GROUND WATER DAMAGES FROM PAST PRACTICES

NM03: THIS IS NOT A WASTE ISSUE BUT A CASE WHERE A PRODUCING WELL CONTAMINATED GROUNDWATER WITH HYDROCARBONS. THE CASE WAS INVESTIGATED BY THE NEW MEXICO OIL CONSERVATION DIVISION UNDER THEIR AUTHORITY TO REGULATE PRODUCTION WELLS.

NM04: GROUNDWATER DAMAGES IN THE HOBBS NEW MEXICO AREA HAVE OCCURRED DUE TO APST PRACTOIL LONGER ALLOWED BY THE NEW MEXICO CONSERVATION DIVISION. THESE PAST PRACTICES HAVE BEEN REGULATED BY BANNED USE OF UNLINED SALTWATER DISPOSAL PITS, THE UIC PROGRAM OF INJECTION WELL REGULATIONS UNDER THE SAFE DRINKING WATER ACT, SPCC REGULATIONS UNDER THE CLEAN WATER ACT AND NUMEROUS PRODUCTION AND DRILLING PRACTICES REGULATIONS. IT SHOULD ALSO BE NOTED THE REFERENCE TO OIL ON AN AQUIFER WAS A 1965 STUDY AND CURRENT STUDIES REFERENCED BY EPA INDICATE CURRENT PRACTICES ARE REDUCING THE ENVIRONMENTAL IMPACT OF THESE OLD PRACTICES

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00073

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RECEIVED MAR 14 1988

March 14, 1988

Docket Clerk
Office of Solid Waste (WH-565)
U.S. Environmental Protection Agency
401 M Street, SW
Washington, DC 20460

Re: Docket No. F-88-OGRA-FFFFF.

Dear Sir:

Pursuant to the notice contained in the Federal Register of January 4, 1988 (53 Fed. Reg. 81), please find enclosed for filing the original and two copies of written comments relevant to EPA's Report to Congress on hazardous waste regulations of the oil and gas industry which are submitted on behalf of the following trade organizations representing oil and gas operators in seven Appalachian states:

Independent Oil and Gas Association of New York
Independent Oil and Gas Association of West Virginia
Kentucky Oil and Gas Association
Ohio Oil and Gas Association
Pennsylvania Natural Gas Associates
Pennsylvania Oil and Gas Association
Tennessee Oil and Gas Association
Virginia Oil and Gas Association
and the
West Virginia Oil and Natural Gas Association.

Very truly yours,

David M. Flannery

David M. Flannery

REL/jlv

Enclosures

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COMMENTS REGARDING THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY'S REPORT TO CONGRESS WITH RESPECT TO THE MANAGEMENT OF WASTES FROM THE EXPLORATION, DEVELOPMENT AND PRODUCTION OF CRUDE OIL, NATURAL GAS AND GEOTHERMAL ENERGY

DOCKET NUMBER F-88-OGRA-FFFFF

ON BEHALF OF THE

INDEPENDENT OIL AND GAS ASSOCIATION OF NEW YORK
INDEPENDENT OIL AND GAS ASSOCIATION OF WEST VIRGINIA
KENTUCKY OIL AND GAS ASSOCIATION
OHIO OIL AND GAS ASSOCIATION
PENNSYLVANIA NATURAL GAS ASSOCIATES
PENNSYLVANIA OIL AND GAS ASSOCIATION
TENNESSEE OIL AND GAS ASSOCIATION
VIRGINIA OIL AND GAS ASSOCIATION
and the
WEST VIRGINIA OIL AND NATURAL GAS ASSOCIATION

SUBMITTED BY:

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March 14, 1988

EXECUTIVE SUMMARY

By notice contained in the January 4, 1988 Federal Register (53 Fed. Reg. 81), the United States Environmental Protection Agency ["EPA"] completed one of the final statutory obligations mandated to it by Sections 3001(b)(2) and 8002(m) of the Resource Conservation and Recovery Act by submitting to Congress its "Report to Congress: Management of Wastes from the Exploration, Development and Production of Crude Oil, Natural Gas and Geothermal Energy." These comments represents the continuing involvement of the following trade organizations with EPA's study process involving oil and gas well drilling and production wastes:

Independent Oil and Gas Association of New York
Independent Oil and Gas Association of West Virginia
Kentucky Oil and Gas Association
Ohio Oil and Gas Association
Pennsylvania Natural Gas Associates
Pennsylvania Oil and Gas Association
Tennessee Oil and Gas Association
Virginia Oil and Gas Association
and the
West Virginia Oil and Natural Gas Association

These trade organizations have come together to call EPA's attention to the fact that the oil and gas industry in Appalachia is very different from the oil and gas industry elsewhere in the nation. A quick recitation of some facts clearly illustrate this point. There is a disproportionately large number of wells in Appalachia, when compared to elsewhere nationally.

Appalachian crude oil and natural gas are strategically important to the nation, contributing a significant percentage of the nation's lubricants.

Our natural gas is important not only because of its volume and close proximity to major Northeast markets, but also because of the extensive use of geologic formations here for the storage and retrieval of natural gas.

Appalachian wells produce small amounts of wastes when compared to elsewhere in the nation. The vast majority of Appalachian wells produce such small amounts of product that they qualify as stripper wells.

Finally, because of the climate, geology, and hydrology of the region, as well as the nature of the drilling and production wastes in the region, less reliance has been placed on disposal techniques used elsewhere in the nation. Concomitantly, increased reliance on disposal techniques such as land application, roadspreading, stream discharge, and annular disposal has occurred.

The first major point of concern raised by the comments of the Appalachian Producers in response to EPA's specific information request in the January 4, 1988 Federal Register relates to the scope of the oil and gas exemption. It has consistently been and continues to be the position of the Appalachian Producers that the scope of the oil and gas exemption, as interpreted by EPA, is overly narrow. While EPA has recognized the critical importance of the scope of the exemption to the study, by delaying a final decision on its

interpretation of the scope of the exemption until a time subsequent to the completion of the Report to Congress, EPA has created a possibility that a class of wastes properly included within the exemption have not, in fact, been studied by the Agency. The Appalachian Producers contend that the biggest problem that EPA faces in its efforts to define the scope of the exemption is the desire by EPA to narrowly construe its scope in contravention of the mandate of Congress on this issue.

EPA Report to Congress continues to misconstrue the damage case evidence, particularly in light of EPA's use of this data to condemn specific disposal techniques. As a general matter, EPA properly describes its study of damage cases as being limited in nature and without statistical significance. The Agency notes that the case study approach is intended only to define the nature and range of known damages, not to estimate the frequency or extent of damages associated with typical operations. For this reason, the Agency concludes that the numbers do not have any statistical significance and do not bear any statistically significant relationship to the actual types and distribution of damages that may or may not exist across the nation.

Nonetheless, it is with great concern that we note that EPA, despite its earlier cautionary statements, relies <u>solely</u> on its damage case analysis to support its conclusion condemning certain disposal techniques used by the industry, particularly in the Appalachian states. These include land application,

roadspreading, stream discharge, and annular disposal. While these specific waste disposal alternatives are discussed more completely in the body of these comments, suffice it to say that in each instance, each disposal option where practiced is comprehensively regulated under presently existing state regulations of the Appalachian states in a manner which insures the environmental acceptability of these techniques and that no harm to human health or the environment occurs. This fact alone should be enough to indicate to EPA that no further regulation of oil and gas drilling or production wastes is necessary in view of the presence of adequate state regulation of any potential environmental problems. A condemnation of these practices without a thorough examination of the various state programs and particularly in light of EPA's continued mischaracterization of many damage cases occurring in the Appalachian states is unsupportable.

In addition, the Appalachian Producers submit that EPA has no basis whatsoever for concluding in the Report to Congress that significant technical improvements in waste disposal techniques in the oil and gas industry are foreseeable. Particularly as it relates to operations in the Appalachian states, this discussion is purely speculative and not supported by any objective findings of the Report to Congress. This is a matter of particular importance because in the Appalachian states, unique waste management practices that have evolved as a function of careful balancing between environmental protection and economical realities indicate that there is no basis for

believing any significant change in waste disposal practices is foreseeable in this region.

The Appalachian Producers are further concerned about the Agency's recommendation that it is necessary to conduct a further review of state and federal programs with a view toward possible modification of these programs to deal with perceived problems regarding industry regulation. Our review of the Report to Congress and our own assessment of the state regulatory requirements in the seven Appalachian states involved, lead us to believe that existing regulatory requirements, be they state or federal, are more than adequate to prevent or mitigate any adverse impacts on the environment caused by the management of oil and gas drilling and production wastes. The overwhelming majority of damage cases cited by EPA in its Report to Congress violate present day regulatory requirements and, in fact, violated regulatory requirements at the time they occurred. EPA has completely failed to recognize the significant evolution of state oil and gas regulatory programs over the last few years or the fact that major changes in many Appalachian state regulatory programs are underway at the current time. Having failed to recognize these facts, we are unaware as to why EPA insists on further study of state regulatory programs and federal regulatory programs with a view toward possible modification in the future.

The Appalachian Producers are also concerned that EPA's economic impact analysis does not adequately assess cost impact on Appalachian operations. EPA's assessment has understated the impact of imposing alternative requirements on the Appalachian

industry. Correspondingly, EPA's economic analysis overstates baseline costs while understating the cost of alternative requirements. The end result is a masking of a true cost of imposing alternative waste management practices on the industry. Additionally, EPA has failed to properly assess the impact of these increased costs on the industry in Appalachia. EPA's analysis is simply not sensitive enough to determine the impacts of very small increases on Appalachian producers. The cost analysis does not recognize that objectionable cost impacts on Appalachian producers will result not only from imposition of hazardous waste regulations, but also from the imposition of any new regulatory requirements under any program.

Finally, the Appalachian Producers note that there is simply no justification for new hazardous or non-hazardous waste regulations as a result of EPA's study of oil and gas drilling and production wastes. EPA's Report to Congress has concluded that existing state and federal regulatory programs are adequate. The Report also has identified the severe economic impacts that would be realized by the oil and gas industry in general should hazardous wastes regulatory requirements be imposed. This impact would be exponentially increased in the Appalachian region should any new regulations be imposed. These factors, in combination with EPA's failure to identify significant unregulated environmental risks, compel the conclusion that no further regulatory requirements are appropriate. We do not believe that it is necessary or appropriate for any new regulatory requirements to be imposed on any segment of the oil and gas

industry. We do, however, support the recommendation by EPA that efforts be taken to develop cooperative approaches with the states that would explore non-regulatory support for current programs in the form of funding, training, or technical support.

Alternatively, although the Appalachian Producers do not feel that it is necessary or appropriate for any new regulatory requirements to be imposed on the oil and gas industry, should EPA nevertheless be inclined to pursue regulations in response to this study, we feel that circumstances surrounding operations in the Appalachian states justify exempting these operations from any of the new regulatory requirements finally promulgated. Because of the minimal nature of the waste streams involved; the proven adequacy of the existing regulatory programs; and the enormous cost impact of imposing additional requirements, a conclusion is compelled that current regulatory and waste management requirements in Appalachia should not be altered as part of the establishment of any national environmental regulatory program to control oil and gas drilling and production wastes.

State regulatory programs have more than enough authority to appropriately change their own programs if there is a need. Expertise also exists at the state level to fashion an appropriate regulatory program which addresses whatever environmental concerns exist, while recognizing the economic capabilities of these operations. A review of this document leads us to believe the Agency has several options available to it which will result in a different regulatory

process as it effects oil and gas drilling at production wastes. In considering these approaches, it continues to be the position of the Appalachian Producers that no regulations of any kind are necessary and that adequate state and federal regulatory authority already exists to handle any environmental problems attributable to the industry. It is our belief that after competent review of the existing state and federal regulatory authorities and disposal practices employed in the Appalachian region, the inalterable conclusion must be that neither Subtitle C or any other regulations justify change.

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I. INTRODUCTION.

On Monday, January 4, 1988 (53 Fed. Reg. 81), the United States Environmental Protection Agency ["EPA"] announced the publication and availability for public comment of its "Report to Congress: Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas and Geothermal Energy" ["Report to Congress"]. The Report to Congress was prepared pursuant to the statutory mandate of Sections 3001(b)(2) and 8002(m) of the Resource Conservation and Recovery Act, 42 U.S.C.S. §§6921(b)(2), 6982(m) (1982) ["RCRA"]. The Federal Register notice announced the availability of the Report to Congress and requested submission of public comment by March 15, 1988. EPA also announced that it would hold five public hearings on the Report to Congress, the first of which was scheduled for Washington, D.C. on February 23, 1988.

These comments are being filed pursuant to the Federal Register notice of January 4, 1988, on behalf of the nine trade organizations representing oil and gas operators in seven Appalachian states. These organization are as follows:

Independent Oil and Gas Association of New York
Independent Oil and Gas Association of West Virginia
Kentucky Oil and Gas Association
Ohio Oil and Gas Association
Pennsylvania Natural Gas Associates
Pennsylvania Oil and Gas Association

Tennessee Oil and Gas Association

Virginia Oil and Gas Association

and the

West Virginia Oil and Natural Gas Association

These organizations will be collectively referred to throughout these comments as the "Appalachian Producers."

II. BACKGROUND OF APPALACHIAN PRODUCERS.

A. Participating Trade Organizations.

To better understand the unique interests of the Appalachian Producers, a brief description of each of the nine participating trade organizations follows:

1. Independent Oil and Gas Association of New York.

The Independent Oil and Gas Association of New York is a non-profit trade organization representing oil and gas producers and related industries operating in New York State. IOGA of New York represents 160 member companies. The purposes of the organization are to protect, promote, foster, and advance the interests of oil and gas producers operating in New York State. The Association was formed in 1980. In connection with these expressed purposes, the organization works to establish better relationships with the New York State Legislature, regulatory agencies, and other oil and gas trade organizations across the country.

2. <u>Independent Oil and Gas Association of West Virginia.</u>

The Independent Oil and Gas Association of West Virginia is a non-profit state trade association representing more than 170 companies engaged in the extraction and production of oil and natural gas in West Virginia. In addition, its membership includes nearly 400 other drilling, contracting, or supplier companies, professional firms, and royalty owners. The organization is dedicated to promoting and protecting a strong, competitive and capable independent oil and natural gas producing industry in West Virginia, as well as on the national level. Its Board of Directors and staff work to maintain close liaison with state and federal agencies regulating the oil and natural gas industry; to disseminate information relevant to member needs; to promote the legislative goals of the Association; and to establish media and community relations to inform and educate the general public on the economic importance of the oil and natural gas industry to the State of West Virginia.

3. <u>Kentucky Oil and Gas Association.</u>

The Kentucky Oil and Gas Association (KOGA) is a non-profit statewide trade association with 589 members, representing crude oil and natural gas producers, mineral royalty owners, drilling companies, and persons in related businesses. The purpose of KOGA is to promote the common interest of the oil and gas industry and to represent the industry on energy, environmental, economic, legislative, and regulatory issues.

4. <u>Ohio Oil and Gas Association.</u>

The Ohio Oil and Gas Association is a non-profit state trade association representing more than 2,100 companies and individuals which comprise independent producers, contractors, professionals, royalty owners, and others in allied fields, all of whom are engaged in, or have a direct interest in, the production of oil and natural gas in the State of Ohio. The purposes of the Association are to protect, promote, foster, and advance the common interest of those engaged in the industry; to act as an information clearinghouse in the collection and dissemination of pertinent information; to promote better operating practices and improved production methods; to conserve oil and gas and to prevent its waste; and, generally, to do such things as may be necessary to accomplish these purposes. The Association also works to establish better relationships with the Ohio General Assembly, the United States Congress, and both state and federal agencies. It also maintains close relationships with other oil and gas industry organizations who have similar interests and goals.

5. <u>Pennsylvania Natural Gas Associates.</u>

The Pennsylvania Natural Gas Associates (PNGA) is a non-profit trade association representing companies engaged in the exploration, development, and production of natural gas along with various industry-related service companies. PNGA is headquartered in Harrisburg, Pennsylvania. Its membership includes approximately 55 companies of various sizes responsible for operating the vast majority of independently owned natural

gas wells located in the Commonwealth. PNGA was formed in 1981 to encourage and promote professionalism in the exploration, development, and production of natural gas; to provide a forum for members of the Association to exchange views and expand their knowledge relative to natural gas exploration, development, and production; to assist members in educating and encouraging the public to consider and appreciate the importance of natural gas issues and to urge members to achieve higher degrees of success and to adhere to high industry standards; to effect liaison with other associations, agents, companies, governmental bodies, and regulatory agencies and to encourage compliance with lawful regulation of all segments of the natural gas industry.

6. <u>Pennsylvania Oil and Gas Association.</u>

The Pennsylvania Oil and Gas Association is a non-profit state trade association representing the state's independent oil and natural gas producers and the allied industries that serve them. The Association's membership numbers approximately 600 companies, 70 percent of which are directly involved in oil and gas production. The aim of the Association is to promote the general welfare of the oil and gas industry in Pennsylvania, and to educate the industry and public on energy, environmental, economic and governmental issues. To accomplish these goals, the organization works within all levels and branches of government, disseminates information through its own publications and the media, sponsors research, and offers a variety of educational programs.

7. <u>Tennessee Oil and Gas Association.</u>

The Tennessee Oil and Gas Association is a non-profit state trade association with 160 members representing companies and individuals engaged in all facets of the oil and gas industry from exploration and development to transportation and sales and others in allied fields such as professionals and suppliers, all of whom are engaged in, or have a direct interest in, the production of oil and gas in the State of Tennessee. The purpose of the Association is the advancement of a common interest of all those engaged in the industry by the collection and distribution of pertinent information, education of the industry and public on matters pertaining to the industry, and to maintain a close liaison with governmental and regulatory agencies of the industry.

8. <u>Virginia Oil and Gas Association.</u>

The Virginia Oil and Gas Association is a trade association organized to promote the interest of the oil and gas industry in the Commonwealth of Virginia. Its activities include providing the general public and legislative and administrative bodies information concerning oil and gas operations in Virginia and representing the interests of its members before legislative and administrative bodies whose actions may have an impact on the industry in Virginia. The Association is open to any person or entity with an interest in the oil and gas industry and its current membership includes individual and corporate representatives from interstate pipelines, local distribution companies, exploration and production companies, including

independent operators and major oil companies, and oil field service and supply companies.

9. <u>West Virginia Oil and Natural Gas Association.</u>

The West Virginia Oil and Natural Gas Association, headquartered in Charleston, West Virginia, is a non-profit state trade association representing producers, contractors, and those businesses that are directly related to the oil and gas industry. It has a membership of approximately 55 companies. The organization is charged with the object of fostering and advancing the common interest of those engaged in the industry by all beneficial or helpful legal actions and to disseminate pertinent data and information useful or necessary in the operations of the oil and gas business. The further duties and services of WVONGA include maintaining close liaison with state and federal agencies regulating the oil and gas industry.

B. <u>Special Characteristics of Appalachia.</u>

These nine trade organizations have come together to call EPA's attention to the fact that the oil and gas industry in Appalachia is very different from the oil and gas industry in the rest of the nation. To illustrate this point, we offer the following facts:

1. <u>Large Number of Wells.</u>

There is a disproportionately large number of wells in Appalachia. While the region has only 3.1 percent of the nation's natural gas production, it has 44 percent of the nation's natural gas wells. For oil, Appalachia has 1.2 percent of the production and 14.2 percent of the wells. In 1985, 26

percent of all new wells drilled in the nation were drilled in the Appalachian states.

2. <u>Strategic Importance of Region.</u>

Appalachian crude oil and natural gas are strategically important to the nation. While our crude oil accounts for only 1.2 percent of the nation's production, it contributes more than 14 percent of the nation's lubricants and more than 24 percent of the nation's automobile lubricants with additives. Our natural gas production is also important beyond its mere volume because of its close proximity to major Northeast markets and because of the extensive use of geologic formations in Appalachia for the storage and retrieval of natural gas.

3. <u>Small Quantities of Waste.</u>

Appalachian wells produce small amounts of waste. Our survey of more than 5,000 primary production oil wells and 12,000 natural gas wells in Appalachia reveals that 97 percent of the wells produce less than an average of one barrel of water per day. Furthermore, our drilling pits are typically among the smallest in the nation.

4. <u>Nearly All Wells Are Stripper Wells.</u>

The vast majority of Appalachian wells produce such small amounts of crude oil and natural gas that they qualify as stripper wells. Our survey reveals that 99 percent of all crude oil wells and 97 percent of natural gas wells satisfy the FERC test for stripper wells. This makes the entire Appalachian region extremely sensitive to any increase in costs.

5. <u>Specialized Waste Disposal Practices.</u>

Finally, a unique combination of waste disposal practices have evolved in Appalachia. The climate, geology, and hydrology of the region as well as the nature of the region's drilling and production wastes have resulted in less reliance on such disposal techniques as evaporation and centralized underground injection and in increased reliance on such disposal techniques as land application, roadspreading, stream discharge, and annular disposal.

These factors and others, taken individually or collectively, create a very special set of circumstances that must be specifically addressed in this study. Our comments on the Report to Congress will focus on these special circumstances and how they should be reflected in EPA's followup to the report.

C. <u>Previous Involvement With EPA.</u>

It should be recognized that these comments have been preceded by a long series of meetings with EPA including ones occurring:

- April 30, 1986,
- July 23, 1986,
- December 13, 1986,
- February 24, 1987,
- June 2, 1987,
- June 9, 1987, and
- July 15, 1987.

Eight formal sets of comments have also been filed by the nine trade associations with respect to various phases of the study

process. The comments include those filed with EPA on the following dates:

- January 15, 1987 [Interim Report on Methodology];
- February 10, 1987 [Economic Impact];
- February 23, 1987 [Damage Cases];
- June 11, 1987 [Damage Cases];
- June 13, 1987 [Interim Report of April 30, 1987];
- August 18, 1987 [Preliminary Draft Report of July 31, 1987];
- October 13, 1987 [Draft Report of August 31, 1987]; and
- November 30, 1987 [Draft Report of October 22, 1987].

In addition, the Appalachian Producers have appeared at public hearings held in Washington, D.C. on December 3, 1986, and February 23, 1988.

We request that the eight sets of written comments previously filed with EPA by the Appalachian Producers and the testimony of the Appalachian Producers at the two public hearings be incorporated into these comments by reference.

As will be evident from a review of these comments, the potential impact of the imposition of <u>any</u> new regulatory requirements on the Appalachian Producers would be devastating. We urge EPA to carefully review the special circumstances surrounding the Appalachian Producers in light of the

Congressional mandate of RCRA Sections 3001(b)(2) and 8002(m) and to determine that no changes in any regulatory requirements are necessary to prevent or mitigate adverse impact on human health or the environment resulting from the management of oil and gas wastes.

III. COMMENTS ON THE REPORT TO CONGRESS.

In many ways, the Report to Congress filed on December 31, 1987 is a vast improvement over earlier versions. This is particularly true when comparing the Report to Congress with the interim draft of that report issued on April 30, 1987, which was repleat with emotion and bad information. Even though improved, the final Report to Congress fails in many ways to satisfy the Congressional mandate for a "detailed and comprehensive study . . . on the adverse effects, if any, of drilling fluids, produced waters, and other wastes associated . . . ." 42 U.S.C.S. §6982(m)(i)(1982).

Beyond the factual and legal errors contained in the Report to Congress, one of the most serious flaws with the report is its overall negative tone. Even though EPA has identified no significant concern over either the current waste management practices of the industry or the adequacy of current regulatory requirements, much of the report is written in unscientific and emotional terms that undermine the objectivity of the report.

These comments will focus on several major issues related to the report beginning with the two matters that were

the subject of EPA's specific information request in the January 4, 1988 <u>Federal Register</u>, i.e., the scope of the exemption and produced water injected for enhanced recovery. Our comments will also address the future direction of the study and the related rulemaking considerations.

A. <u>The Scope of the Exemption is Overly Narrow.</u>

By identifying the scope of the exemption in the January 4, 1988 <u>Federal Register</u> publication as a matter requiring special comment, EPA has recognized the critical nature of this issue. The Appalachian Producers first discussed the scope of the exemption with EPA in a meeting held on April 30, 1986. At that time, we urged EPA to make an early determination as to which wastes were properly included within the scope of the exemption, and therefore, within the scope of the study.

Notwithstanding this early discussion of the issue, we now find ourselves again commenting on the appropriate interpretation of this term -- after the final Report to Congress has been completed. By delaying a final decision on the scope of the exemption until a time subsequent to a completion of the Report to Congress, EPA has created the very real possibility that it may define a class of wastes that are properly included within the exemption only to find that the Report to Congress has not considered those wastes.

The biggest problem contributing to EPA's inability to define the scope of the exemption is its apparent desire to narrowly construe the exemption and, therefore, the nature of the wastes which should be included within the study. Both RCRA

Section 3001(b)(2) and Section 8002(m)(1) direct EPA to examine "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas . . . ." Neither the statute nor the legislative history contain any amplification of the terms "drilling fluids" and "produced waters"; however, the legislative history does contain an elaboration of the meaning of the term "other wastes associated." On page II-17 of the Report to Congress, EPA recognizes the limited nature of this legislative history, but nevertheless, extends that legislative history not only to "other wastes associated," but also to "drilling fluids" and "produced waters."

We submit that any reasonable interpretation of the scope of the exemption results in the conclusion that "drilling fluids" and "produced waters" should be included without limitation in the exemption, and, therefore, the study. Neither the statute nor the legislative history suggest that Congress contemplated any limitations whatsoever on the scope of the exemption of these wastes. Instead, it appears that Congress intended this exemption to apply to drilling fluids and produced waters whether they are discarded at the wellhead or at any other point downstream in the exploration, development, or production of crude oil or natural gas. We believe that the exemption terminates with respect to drilling fluids and produced waters only at the point of completion of the process of exploration, development, or production of crude oil or natural gas which should generally occur at the point of delivery of crude oil for refining or of natural gas for manufacturing or burning.

With respect to "other wastes associated," the legislative history suggests that Congress intended that in interpreting whether those wastes would be included within the exemption or not, EPA should take account of such factors as:

- the relationship of such waste to primary field operations;
- the point of custody transfer;
- the point of production separation, dehydration or transportation; and
- manufacturing operations.

The difficulty with these criteria when applied to real world situations is that tying the scope of the exemption to such factors as custody transfer may cause the scope to vary even within individual crude oil or natural gas systems. As a matter of administrative convenience, therefore, we urge EPA to define the scope of the exemption with respect to "other wastes associated" to have the same bounds as the exemption applicable to drilling fluids and produced waters, i.e., all wastes should be exempt to the point of delivery of crude oil for refining or of natural gas for manufacturing or burning.

Beyond administrative convenience, we believe that Congress intended EPA to apply a broad interpretation to defining the scope of the exemption. The rationale behind broadly interpreting the exemption is obvious. A broad interpretation of the exemption would mean that EPA would broadly study these wastes leading to specific regulatory determinations as to specific waste streams. This view was confirmed in the November

17, 1987 letter to EPA Administrator Thomas from the Honorable Quentin N. Burdick, Chairman, U.S. Senate Committee on Environment and Public Works. A copy of Senator Burdick's letter is attached and identified as Exhibit A. In that letter, Senator Burdick stated:

> A review of §8002(m) of RCRA and the legislative history associated with that section reveals the clear intent of Congress that the scope of the study be broadly interpreted to include all drilling fluids and produced waters wherever they occur as well as associated wastes intrinsically derived from primary field operations. Given this Congressional intent, I urge you to include within the study the broadest possible scope of wastes associated with this industry.

We also urge EPA to broadly interpret the scope of the exemption and the wastes which are properly included within its study of the oil and gas industry. A broad interpretation of the exemption would be consistent with the Congressional mandate related to the study and would not preclude EPA from regulating any wastes included within the exemption. To the contrary, including a waste within the exemption would allow that waste to be carefully studied by EPA with a view towards making an informed decision as to whether or not that waste should be subject to regulation pursuant to RCRA Subtitle C or pursuant to any other regulatory program. Thus, a broad interpretation of the oil and gas exemption at this time would preserve EPA's right to impose further regulation on the exempt waste streams at a later date should that action become warranted.

Before turning to several specific items of concern about EPA's current interpretation of the scope of the exemption, we will recognize several aspects of the current interpretation that we can support. First, EPA has abandoned its earlier proposal that the exemption should extend only to wastes that are generated at the primary field site. Even with respect to "other wastes associated," the legislative history expressly provides that the exemption was meant to apply to wastes "intrinsically derived from the primary field operations." This would obviously extend to those wastes whether generated at the primary field site or elsewhere as long as they were "intrinsically derived from the primary field operations."

EPA has also given proper recognition to the fact that even marginal field operations will result in some small volume of non-exempt wastes necessarily becoming mixed with such exempt wastes as reserve pit contents. See Report to Congress, p.II-17. In such a situation, EPA is correct in extending the exemption to include the mixture of the exempt and the non-exempt waste. Any obligation therefore, to segregate materials should extend only to the segregation of "unused" materials, such as pipe dope and motor oil, and not to the portions of those non-exempt wastes that become inherently mixed with exempt waste during normal field operations.

EPA has also correctly included within the scope of the exemption "waste from subsurface gas storage and retrieval." See Report to Congress, p.II-20. This is an obvious reference to wastes generated by wells associated with the storage and

retrieval of natural gas in geologic formations. Those wells are drilled and completed using the same techniques that are utilized in drilling primary production wells. The operation of gas storage wells is also similar to production wells, except for the injection of natural gas during the summer injection cycle. In most cases, storage fields are developed from depleted, or nearly depleted, natural gas production fields. During withdrawal of the natural gas, waters may be produced that are very similar to the waters that are produced by a typical Appalachian production well. The inclusion within the exemption of wastes from subsurface gas storage and retrieval is, therefore, entirely appropriate.

We also support EPA's conclusion that the exemption should extend not only to material extracted from or injected into the ground, but also to material introduced at the surface to prevent freezing or to remove paraffin or otherwise to enhance the performance of surface facilities. <u>See</u> Report to Congress, p.II-18.

We are also supportive of EPA's efforts in paragraph 3 on page II-18 of the Report to Congress to clarify the breakpoint between primary field operations on the one hand and transportation or manufacturing on the other. While EPA's language is not entirely clear on this point, we believe EPA intends for this breakpoint to be defined, in the case of crude oil, at the point where the oil is transported to a refinery or to a refiner, and in the case of natural gas, at the point where the gas is transferred to a carrier for transport to market. As

we advised EPA in our comments of October 13, 1987, a very large percentage of crude oil in Appalachia is moved from stock tanks located at or near the well site to intermediate storage facilities prior to being transported to refineries. While reasonable efforts are made at the well site stock tanks to remove water from the crude oil prior to being loaded into trucks for transportation to these intermediate storage facilities, there is necessarily a quantity of water that is carried with the oil to the intermediate storage areas where is it removed and handled as nonhazardous waste. The volume of water generated at the intermediate storage tanks is certainly much smaller in quantity than the water that is generated at the stock tanks located at or near the well site. However, it is important that the exemption extend to all of this produced water since it is all part of the integral process of accumulating the crude oil in advance of its transportation for refining. While we believe EPA's interpretation of the scope of the exemption as contained on page II-18 of the Report to Congress, contemplates this activity being within the scope of the exemption, additional clarification of this point would be useful.

Turning to areas of disagreement with EPA's current interpretation of the scope of the exemption, we offer the following comments:

1. <u>Separation Media.</u>

On page II-20 of the Report to Congress, EPA identified among non-exempt wastes "waste iron sponge, glycol, and other separation media." We strongly disagree with EPA's

determination that these materials should not be included within the scope of the exemption and the study. These wastes intrinsically are derived from primary field operations and, as such, fall within the category of exempt waste known as "other wastes associated." EPA itself concedes on page II-18 of the Report to Congress that exempt wastes include those wastes associated with measures "to remove impurities" from crude oil or natural gas. We urge that these materials be included within the scope of the exemption.

2. Recycled Materials.

While EPA addresses produced water that is used in enhanced recovery (see subsequent comment), its current interpretation of the scope of the exemption does not address the reuse or recycle of other materials. 40 CFR §261.6 identifies the circumstances under which these materials would not be treated as hazardous waste under the existing RCRA Subtitle C regulatory program. EPA's interpretation of the scope of the exemption should recognize this universe of waste as not being subject to hazardous waste regulation.

B. Produced Water Injected for Enhanced Recovery Should Not Be Considered a Waste.

The second of the specific issues identified in the January 4, 1988 Federal Register relates to whether produced water injected for enhanced oil recovery should be considered a waste. We believe the answer to this question is clearly no. On page II-18 of the Report to Congress, EPA proposes to interpret the scope of the exemption as including the injection of produced

water for the enhanced recovery of oil and gas. We have no doubt but that produced water used in this application is not a waste material and should not be considered for inclusion within any RCRA Subtitle C or other regulatory program aimed at the regulation of wastes. Absent the availability of produced water for this purpose, operators of enhanced oil recovery facilities would be required to acquire water for injection purposes. Produced water is therefore an effective substitute for water that would otherwise need to be acquired to facilitate enhanced recovery operations and should not be considered a waste.

C. EPA Has Correctly Included the Seven Appalachian States Within Zone Two of the Study.

We commend EPA for maintaining the geographical integrity of the boundaries of Zone Two in its Report to Congress as detailed on pages I-6 and I-7. Zone Two, comprising the Appalachian region, consists of the states of Kentucky, New York, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia.

Six of the seven states represented by the trade organizations filing these comments were considered by EPA to be within Zone Two of its original Draft Sampling Strategy dated May 5, 1986, which guided EPA's field testing during the summer of 1986. See U.S. EPA, Office of Water Regulations and Standards, Oil and Gas Exploration, Development and Production, Sampling Strategy-Draft (May, 1986). At a meeting with EPA on July 23, 1986, the Appalachian Producers requested that Ohio be added to Zone Two in order to give the zone a geographic scope encompassing the Appalachian region. EPA had no objection to

such grouping and this alignment has been reflected in EPA's subsequent reports concerning this study.

4. EPA's Damage Case Review is Flawed and Does Not Support the Agency's Assessment of Specific Disposal Techinques.

1. General.

EPA properly describes its study of damage cases as being limited in nature and without statistical significance. The Agency notes on page I-7 of the Report to Congress that the case study approach called for by RCRA Section 8002(m) is intended only to define the nature and range of known damages, not to estimate the frequency or extent of damages associated with typical operations. The numbers therefore do not have any statistical significance and do not bear any statistically significant relationship to the actual types and distribution of damages that may or may not exist across the nation. EPA also notes on page I-8 of the Report to Congress that the total number of cases bears no relationship, either implied or intended, to the total extent of damage from oil or gas operations caused at present or in the past.

Nonetheless, it is with great concern that we note that EPA, despite these cautionary statements , relies solely on its damage case analysis to support its conclusion criticizing certain disposal techniques used by the industry. On pages VIII-1 and VIII-2 of the Report to Congress, EPA criticizes the use of several technologies as being less reliable and cites as authority damage cases occurring in Appalachia. The use of these

damage cases to support an overall conclusion that the technologies or practices at issue (land application, roadspreading, annular disposal and stream discharge), are less reliable and, thereby, increase the potential for environmental damage in certain locations is unsupportable. This is particularly so given EPA statements in the Report to Congress that its damage case study is limited in nature and without statistical significance. For this reason, EPA's use of this data in this manner is misleading and highly inconsistent. The characterization of annular disposal, land application, roadspreading, and stream discharge as environmentally unreliable is even more distressing in light of the justifications set forth later in these comments which indicate that these practices can and are practiced in Appalachia in a way which protects environmentally sensitive values.

Specifically, EPA emphasizes in the Report to Congress that its damage case study is intended "to gain familiarity with ranges of issues involved" and is not intended to be a "statistically representative record of damages in each State." See Report to Congress, p.IV-10. Again however, based solely on these damage cases, EPA makes a determination that certain disposal practices are "less reliable in locations vulnerable to environmental damage." See Report to Congress, p.VIII-1. As previously mentioned this is not only misleading but inconsistent, particularly in light of the fact that the environmental waste disposal technologies which EPA criticizes as less reliable are in fact carried out under extensive state regulatory control in an environmentally acceptable way.

2. Land Application.

In its Report to Congress, EPA identified the land application of drilling fluids as an unreliable disposal technology that has resulted in harm to the environment. See Report to Congress, p.VIII-1. EPA's conclusion about the land application of drilling fluids is based upon a wholesale failure by the Agency to assess the merits of this disposal technique. The environmental acceptability of the land application of drilling fluids has been successfully and repeatedly demonstrated in West Virginia. Land application of drilling fluids, where properly controlled, is an environmentally acceptable disposal technique which is, and continues to be, adequately regulated at the State level.

The damage case upon which EPA relies to condemn land application, WV 13 [See Report to Congress, p.IV-24], has been badly mischaracterized factually. In correspondence submitted to EPA on August 13, 1987 from the Appalachian Producers, it was documented that the observed vegetation stress reported in that case lasted only two to three weeks and was followed by a full recovery. EPA has ignored documentation submitted by the State agency and the Appalachian Producers pointing out that there was not permanent damage to vegetation and that the reported chloride values were related to the contents of a reserve pit and not the soil.

EPA makes the additional statement that the chloride concentrations authorized for land application in West Virginia are higher than the native vegetation can tolerate. See Report

to Congress, p.IV-24. This allegation is totally unsupported by the study and contrary to the fact that several thousand such land applications have occurred in West Virginia since July 1985 with no reported case of permanent vegetation damage. Finally, in its assessment of waste disposal technologies, EPA completely fails to address the land application of drilling fluids as a currently employed waste management practice. In short, EPA's conclusion that land application is an environmentally suspect waste disposal technology is completely unfounded in light of current practice in the industry of the Appalachian region.

Land application of drilling fluids is important to the Appalachian operators because it provides an environmentally safe and economical method for the disposal of drilling pit fluid. Climatological and geological constraints in Appalachia make it impractical to use disposal techniques that are used by other operators in other regions of the country. For instance, because the net precipitation exceeds the net evaporation rate in the Appalachian states, evaporation of drilling fluids, as is commonly practiced in the Southwest, is not possible. The low permeability of geological formations which are available for injection of drilling wastes severely reduces disposal well injection rates and therefore makes underground injection of wastes impractical in most cases. The remote locations and rugged terrain in most of Appalachia increases transportation costs significantly and thereby creates a disincentive to the use of centralized treatment or injection facilities in the Appalachian region. Newly developed disposal techniques, such as

solidification, are cost prohibitive. The marginal profitability of Appalachian wells is such that any additional costs may render drilling uneconomical.

In West Virginia, a general permit for the land application of drilling fluids was issued by the Department of Natural Resources in July, 1985. Since that time, approximately 2,000 drilling pits have been sampled, treated, land applied, and reported. Out of these 2,000 cases, there has been only one case where any impact on the environment was detected -- a case which EPA has, as previously commented upon, badly mischaracterized.

Obviously, the disposal of 2,000 pits without a problem demonstrates that, as conducted in accordance with permitting requirements presently existing in West Virginia, land application of drilling fluids has proven itself an environmentally acceptable disposal technique. The fact that land application has proven itself to be an effective and environmentally safe mechanism for the disposal of these fluids is supported by three facts.

(1) The average drilling pit capacity in Appalachia is only about 2,000 barrels or less. A one-time land application of this small volume of waste, conducted in accordance with the carefully controlled requirements of the West Virginia general permit, has been shown not to harm the environment.

(2) Most wells of Appalachia are drilled with rotary drilling rigs using air as a circulating medium. Discharged pit fluids are usually encountered in shallow formations and therefore have low concentrations of pollutants. Unlike drilling

fluids elsewhere, drilling fluids used in the Appalachian states are water-based with few additives. Where these fluids are used at all in drilling a well, they generally consist of water mixed with low concentrations of potassium chloride, a material used in agricultural fertilizer.

(3) The final factor contributing to the environmental acceptability of land application of drilling fluids is the current adequate regulation and enforcement of this practice. Despite the success of the first land application general permit issued in July of 1985, when the permit was reissued in January of 1988, a number of changes which further insure protection of the environment were made. Chloride concentrations were reduced from 25,000 ppm to 12,500 ppm. Additional monitoring of total organic compounds and other constituents is now required. Additional restrictions concerning the discharge of pit fluids were included as terms of the permit as well.

In conclusion, EPA's blanket condemnation of the practice of land application of drilling fluids flies in the face of a three year history of environmentally successful use of this technique in West Virginia of over 2,000 reported discharges. The single case upon which EPA relies has been badly misconstrued to suit the Agency's self-serving conclusion that land application is environmentally unsound and ignores the true facts of that case. A proper and complete examination of this disposal practice must lead to the inalterable conclusion that, as practiced in Appalachia and particularly in West Virginia, land application of drilling fluids is environmentally sound and protective of the environment.

3. <u>Stream Discharge.</u>

As was the case with its condemnation of land application, while properly describing its study of damage cases as being limited in nature and without statistical significance [<u>See</u> Report to Congress, pp. I-7, I-8], EPA nevertheless relies solely on these damage cases and their analyses to support the conclusion criticizing stream discharge as a disposal technique. <u>See</u> Report to Congress, pp.VIII-1, VIII-2.

While the Appalachian Producers are sensitive to the Agency's concern that stream dischargers assure that no harm will result to receiving water bodies, we believe that stream discharges, where properly carried out, are a viable disposal option in the Appalachian Basin. Stream discharge is a viable disposal option not only because of the availability of a surplus water budget coupled with relatively low volume of waste being produced by Appalachian operations and the concomitant economically marginal nature of the region's stripper well industry, but also because the practice is already subject to a comprehensive framework of regulations under EPA's NPDES program. The Agency's analysis has failed to take these facts into account.

Operators who wish to use this disposal option are required to obtain a permit for each stream discharge; to abide by a set of nationally recognized effluent guidelines; and to meet specific state water quality standards. The greatest existing deficiency in the program is that EPA's effluent guidelines allow stream discharges only with respect to produced water from <u>stripper</u> oil wells. As the result of a federal court

decision and a petition filed by the nine Appalachian trade associations on July 14, 1987, EPA currently has its effluent guidelines under review for purposes of determining whether the guidelines are appropriate in all applications. The Appalachian Producers requested the suspension of existing zero discharge requirements for all oil and gas operations in seven Appalachian states. EPA has been requested to consider whether the effluent guideline is overly stringent, particularly in light of its application to wells in the Appalachian states where evaporation and underground injection are not generally available.

The concern which EPA expresses over stream discharges in its Report to Congress is clearly limited to potential impact on sensitive or fragile waterways. We are convinced that working with EPA to address the petition for review of the effluent guideline under the Clean Water Act is the appropriate mechanism to regulate a viable and appropriate disposal practice as presently engaged in the Appalachian region. Accordingly, we also feel that because of the existence of comprehensive regulation under the Clean Water Act, EPA's condemnation of this practice as part of its Report to Congress is an attempt by the Agency to achieve regulation of this practice under separate authority. Because EPA has not studied the environmental impact of stream discharges appropriately in this study and because such discharges are presently comprehensively regulated and, indeed, more appropriately regulated under the federal Clean Water Act, the conclusion in the Report to Congress that stream discharge is

environmentally unreliable is both inappropriate and factually unfounded.

4. Annular Disposal.

Annular disposal, as presently engaged in Appalachia, is an environmentally sound and commercially viable disposal option for brine. Once again, as in its previous treatment of the land application and stream discharge disposal options, what EPA has given with one hand, it is taken away with the other in an inconsistent manner. While EPA properly describes its study of damage cases as being limited in nature and without statistical significance [See Report to Congress, pp.I-7, I-8], it nevertheless relies solely on the damage case analysis to support its conclusion criticizing annular disposal as unreliable. See Report to Congress, pp.VIII-1, VIII-2. This conclusion is inconsistent, misleading, and only exacerbated by the fact that EPA relies on a case allegedly giving rise to damages in which disposal practices used in that case are now no longer employed by the industry in Ohio.

More specifically, while EPA emphasises that 58 out of its 61 damage cases occurred in the last five years [See Report to Congress, p.IV-1], the sole case upon which it relies to condemn annular injection of produced water occurred in 1975. See Report to Congress, p.IV-16. Reliance on this case by EPA is clearly inconsistent with the Agency's goal in the study to "emphasize development of recent cases that illustrate damages created by current practices under current state regulations." It is also contrary to EPA's reliance on a five year time frame

for use of cases in its Report to Congress. <u>See</u> Report to Congress, p.IV-1.

EPA's statement that "historical damages that occurred under prior engineering practices or under previous regulatory regimes has been excluded, unless such historical damages illustrate health or environmental problems that the Agency believes should be brought to the attention of Congress now" [<u>See</u> Report to Congress, p.IV-1], offers a tenuous basis for the use of the <u>Donofrio</u> case (OH 39), and is totally self-serving. This justification affords EPA the opportunity to report to Congress on <u>any</u> damage case despite the fact that the damage case is not likely to occur in this day and time, because of adequate existing regulatory programs.

Since the <u>Donofrio</u> case occurred in 1975, applicable regulatory requirements in Ohio regarding annular disposal have been substantially modified. EPA's use of this case once again allows the Agency to construe data in a light most favorable to the Agency's conclusion that annular disposal is unreliable environmentally and also allows EPA to ignore the merit of this disposal technique as it is presently in practice under existing state regulations in Ohio.

In Ohio, an operator desiring to conduct annular disposal must seek permission of the State regulatory agency. Any annular disposal well must be constructed with the surface casing which uses cement or prepared clay to completely seal off the casing to a depth of at least fifty feet below the deepest underground source of drinking water. To avoid corrosion of

pipes and fittings, all produced water is transported to the annular disposal well in an airtight system. Volume limitations are placed on the amount of material that can be placed into the well and no pressure can be used, except that as supplied by the force of gravity. Every five years, mechanical integrity tests are required on annular disposal wells to assure their ability to prevent contamination of surface or subsurface soils or waters. Once a well ceases production of oil or gas, all annular disposal operations must cease and the well must be plugged.

It should also be pointed out that the geological formations in Ohio allow the practice of annular disposal to be carried out in an environmentally suitable fashion. There are several reasons why this is the case.

- No open commercial oil and gas zones exist from the top of the surface casing to the top of the production casing cement.
- The injection zone is isolated and deep.
- The strata of Ohio are level, dipping approximately one degree to the southeast. This lessens the possibilities of up-dip migration of brine out of the injection zone.
- Cable tool drilling logs have provided the State of Ohio with accurate descriptions of where fluid producing and fluid taking zones are located.
- The geologic conditions are fairly uniform over the eastern half of the State of Ohio. This coincides with the area of production in the state.

In the twenty-one years that annular disposal has been used in Ohio, there have been less than ten cases of known ascertainable environmental damage. These cases have occurred

under disposal practices and regulatory requirements that are no longer applicable. As previously mentioned, the principle case upon which EPA relies in condemning annular disposal is the Donofrio case, which occurred in 1975. No other efforts have been made by EPA to assess the environmental acceptability of annular disposal. Reliance upon a single damage case that occurred more than thirteen years ago under regulations and disposal practices that are no longer in effect and the concomitant wholesale failure by EPA to examine in any sense the current practices of the industry as regards annular disposal and how the industry is regulated in Ohio at the present time constitutes a totally inadequate basis for reaching a conclusion that annular disposal is environmentally unacceptable. We would be willing to work with EPA to conduct the type of study that would be necessary to prove that annular disposal is a meritorious disposal option of suitable environmental acceptability.

5. Well Fracturing.

EPA is incorrect in its statement that the fracturing of a well can result in contamination of nearby water wells. See Report to Congress, p.IV-22. Such a statement is completely without support in the study. In fact, we know of no case where this has occurred given proper casing. The zones which are fractured are several thousand feet below the deepest fresh water zones making contamination of the fresh water zones extremely unlikely.

6. Roadspreading.

EPA, as one of its conclusions, condemns the practice

of "landspreading or roadspreading of reserve pit contents" as an example of technologies or practices that are less reliable in locations vulnerable to environmental damage. See Report to Congress, p.VIII-1. As support for this conclusion, EPA cites the damage case, WV 13. Once again, the recurring problem with this report is that EPA emphasizes that its damage case study is intended "to gain familiarity with ranges of issues involved" and not to be a "statistically representative record of damages in each State" [See Report to Congress, p.IV-10], and then based solely on these damage cases makes a determination that certain disposal practices are "less reliable in locations vulnerable to environmental damage." See Report to Congress, p.VIII-1.

EPA is also flatly erroneous in relying on WV 13 to condemn roadspreading of reserve pit contents. WV 13 involves landspreading, an environmentally acceptable waste disposal practice as detailed previously in these comments, and which does not pertain to roadspreading of brine or other drilling fluids. In fact, roadspreading of reserve pit contents is not employed as a waste disposal practice in West Virginia. Other Appalachian states, however, have extensive programs to regulate roadspreading in an environmentally sound manner.

For instance, in Ohio, regulation of produced water roadspreading is a matter of statutory law. No roadspreading of reserve pit contents is allowed. Local governmental entities have the authority to allow surface application of brines to roads it owns or has the right to control for purposes of dust or ice control, however, a resolution must be adopted permitting

such application. Public hearings on whether or not to adopt such a resolution to permit surface application of brine must be held. Input by State and federal regulatory authorities is provided for in the statute. Performance guidelines are additionally set forth in the statute which dictate where brine may or may not be applied; when brine may be applied; the technology by which brine may be applied; and the pressure at which brine may be applied. Prior to the application of brine to road surfaces, the applicant must submit a plan which identifies the sources of brine to be used; identifies any transporters of the brine; identifies the places to which the brine will be applied; and describes the method, rate, and frequency of brine application. Additionally, local governmental authorities may attach whatever terms and conditions seem suitable to the plan prior to any actual roadspreading. *See generally* ORC 1509.226.

In Pennsylvania, the Department of Environmental Resources' *Oil and Gas Operators' Manual* prescribes, in Chapter Four, applicable requirements for roadspreading of *produced water* for dust control and road stabilization. Requirements have been adopted under the authority given the Department pursuant to the Pennsylvania Clean Streams Law. Appropriate rates of application must be used in roadspreading. A plan which minimizes the potential for pollution from the use of brine for dust control must be submitted to the DER for its approval prior to implementation. This plan must include the following: (1) the name, address, and telephone number of the person seeking the approval; (2) a statement from the municipality or other person

authorizing the use of brine on their roads; (3) a map of the municipality or area identifying the roads which are to receive the brine; (4) a description of how the brine will be applied including the equipment to be used and the method for controlling the rate of application; (5) the proposed frequency of application; (6) identification of the geologic formation from which the brines are produced; (7) identification of any materials which may be included with the brine, such as drill cuttings, detergents, friction reducers, hydro-fracturing materials and a chemical analysis of certain parameters. The DER prescribes additional terms and conditions under which brine may or may not be applied including brine application rate; locations where brine may not be applied in terms of roadgrade; locations where brine may not be spread on roads including what roads; appropriate labelling of vehicles applying brine; and submission of monthly reports indicating roads to which brines were applied, quantities of brine applied, and dates of application. <u>See generally</u> Department of Environmental Resources, <u>Oil and Gas Operator's Manual</u>, pp.IV-72, IV-74. In addition, PNGA sponsored an independent study entitled "The Feasibility of Utilizing Production and Other Oil and Gas Well Fluids as Dust Palliatives and Deicers" in 1984. This study reviewed Pennsylvania's roadspreading program and concluded "since oil and gas well fluids are not substantially different in composition from commercial salt, similar environmental concerns are apparent. However, with proper management techniques (application procedures, and rates, etc.) to minimize environmental impact,

these fluids can be used effectively for dust and ice control." Moody Study, December, 1984, p.ii.

Finally, in New York, a comprehensive system of regulation of roadspreading of brine is in place under 6 NYCRR Part 364. Under these regulations, permits are required for the roadspreading of brine which must be renewed periodically. Landowner approval is required before brine may be roadspread. Analyses of the brine must be done for a variety of parameters. There are volume restrictions as to the amount of brine which may be roadspread, as well as restrictions regarding location of application. No variances are allowed from these regulations.

The foregoing recitation clearly points out the extensive level of regulation to which this activity is subject in the Appalachian states to insure that the practice is carried out in an environmentally safe, acceptable manner contrary to the conclusion reached by EPA in its Report to Congress.

7. Other Comments Relating to EPA's Flawed Damage Case Review.

We commend EPA for its recognition in the vast majority of damage cases cited in Chapter IV of its Report to Congress that current state regulatory programs are frequently violated by the types of damage cases relied upon by EPA. This recognition by EPA, we feel, clearly supports the contention of the Appalachian Producers that adequate authority exists under state and federal regulatory programs currently in effect to handle any alleged environmental problems that result from improper waste disposal practices in the industry. This assessment is a vital

part of the Section 8002 study and is a statutorily mandated factor to be considered by EPA in its decision as to whether or not, if at all, to impose new regulations on the industry. Given the recognition by EPA in its Report to Congress that state programs are being violated, it is clear that no new regulations are therefore necessary.

Relevant to the topics discussed in Chapter IV of the Report to Congress concerning illegal disposal of oil and gas wastes in West Virginia and Pennsylvania, EPA continues to make unsupported and highly emotional comments about this alleged practice. For instance, on page IV-17 of its Report to Congress, EPA makes the totally unfounded remark that "environmental damage from illegal disposal of wastes associated with drilling and production is by far the most common type of problem in West Virginia" and that "results of illegal disposal include fish kills, vegetation kills, and death of livestock from drinking polluted water." As pointed out in the comments of the Appalachian Producers filed on August 18, 1987, there is simply no basis for EPA to conclude that illegal disposal is a common problem in West Virginia. The Agency has conducted no investigation to relate the number of violations of state regulatory programs to the total number of cases involved to know whether the West Virginia experience is better or worse than might be expected with any other regulatory program. Moreover, the damage cases cited by the Agency involving vegetation kills and death of livestock are clearly not related to illegal disposal of waste.

The statements referred to in the damage case chapter are unfounded and intemperate and it is improper for EPA to have included them in their Report to Congress. This is particularly so in light of the Agency's statement on page I-8 of its Report to Congress that no relationship has been established between documented damages and violations of state or other federal regulations.

In support of its conclusion regarding alleged illegal disposal in West Virginia, EPA continues to rely on WV 18 as a damage case. We previously requested that EPA delete this damage case from its consideration. <u>See</u> June 11, 1987 comments, p. 6 and August 18, 1987 letter to Dan Derkics, p. 6 item 11. The basis for the requested deletion from consideration was because the landowner in that case <u>intentionally</u> used a pit for purposes of supplying water for his domestic cattle. The situation related to an agreement reached between a landowner and an operator not to reclaim a pit and, instead, to allow it to receive water from a well to be used for domestic livestock watering. We pointed out that <u>current</u> statutory law required that such pits be reclaimed within six months following completion of drilling. Additionally, the West Virginia Department of Energy stated in comments--comments recognized in a footnote to this case in the Report to Congress--that "now the Division does not allow that type of practice and would not allow landowners to subvert the reclamation law." In the face of comments from operators and State regulatory officials in the state where the alleged problem occurred, it is completely

unclear why the Agency continues to rely on this damage case to support its somewhat tenuous conclusion.

Regarding alleged illegal disposal of oil field wastes in Pennsylvania, EPA acknowledges on page IV-20 of its Report to Congress that spills or accidental releases of oil or gas wastes in Pennsylvania are not routinely associated with extraction of oil and gas. However, EPA continues to characterize the Pennsylvania experience, in the context of discussing damage cases PA 02 and PA 09, in an inflamatory manner by stating that "spills in this area of Pennsylvania appear to represent deliberate, routine, and continuing illegal disposal of waste oil." There is no evidence to support this callous assertion by EPA and, in fact, the Appalachian Producers have in the past and continue to dispute this statement. EPA's reliance on this statement is completely unfounded.

In its discussion and condemnation of damage to water wells allegedly caused from oil and gas well drilling and fracturing, EPA in its Report to Congress continues to make erroneous statements. Of particular concern is footnote 17 on page IV-21 of the Report to Congress, where EPA notes as follows:

> According to members of the Legal Aid Society of Charleston, West Virginia, land owners have little control over where oil and gas wells are sited. Although a provision exists for hearings to be held on the question of siting of an oil and gas well, this process is rarely used by private landowners for economic and other reasons.

This subjective statement incorrectly characterizes the law and ignores the basic principal that a provision does, in fact, exist for a landowner to challenge the siting of a prospective oil or

gas well. The mere fact that landowners make a conscious decision not to use this provision does not mean, as EPA contends in its blanket statement, that landowners have little control over the location of prospective oil and gas wells.

Additionally, EPA has recognized in its Report to Congress that where there is contamination of a fresh water source, State regulations presume oil or gas drilling is responsible if located within 1,000 feet of the water source. EPA points out that West Virginia has no automatic provision requiring drillers to replace water wells lost in this manner and therefore implies that the West Virginia regulatory program is somehow deficient in this regard. This subtle manipulation of the law ignores the comments of the Appalachian Producers submitted on August 18, 1987, which noted as follows:

> Finally, while West Virginia has no automatic provision which requires a driller to replace a water well, we suggest that West Virginia is in no different a position than are most other states which require some showing that the water well was contaminated by the driller before there is an obligation to replace it. In West Virginia there is, of course, a presumption that if an oil or gas well is within 1,000 feet of a contaminated water well, it is presumed that the contamination resulted from the oil and gas well. In short, contrary to the statements appearing on page 13, there is considerable involvement of the surface owners in the process of assuring that oil and gas well drilling does not adversely affect water wells.

Further, EPA in its Report to Congress continues to rely on a damage case, WV 17, in support of its conclusion that contamination of water wells result from oil and gas operations.

The Agency's continued reliance on this case ignores comments also found in the August 18, 1987 letter to Dan Derkics noting that the case initially did not even involve waste disposal and, in any event, subsequent regulatory changes rendered the case irrelevant. Additionally, no statement has been added, as is apparently the case in all other damage cases cited by the EPA study, that current regulations adequately address this type of alleged problem.

In discussing problems with enhanced oil recovery and abandoned wells in Kentucky at page IV-24 through page IV-26 of its Report to Congress, EPA relies on the Martha Oil Field case. While we do not take issue with the characterization of this case, we have previously noted in our comments dated November 30, 1987, that the case must be placed in proper perspective in light of EPA's statutory mandate to assess the adequacy of existing state and federal regulatory programs to prevent or mitigate environmental damage. EPA has, on page IV-26 of its Report to Congress, noted in a paragraph the Agency's response to the Martha Oil Field problems. However, although we commend EPA for noting that response which the Agency has taken there, it should have added a concluding statement noting that the Agency's response was an example of the adequacy of existing federal regulatory programs to deal with environmental damages caused by oil and gas operations.

E. EPA Has No Basis for Its Conclusion that Significant Technical Improvements in Waste Disposal Techniques in the Oil and Gas Industry are Foreseeable.

While EPA's Report to Congress ultimately concludes that any program to improve the management of oil and gas wastes in the near term will be be based largely on technologies and practices in current use [See Report to Congress, p.VII-2], we are concerned about several statements appearing elsewhere in the Report that seem to suggest that significant improvements in waste disposal technologies are foreseeable. We strongly disagree with this conclusion, particularly as it applies to operations in the Appalachian states.

Our particular concern is focused on the conclusory statement contained on page VIII-2 of the Report to Congress in which EPA states that it foresees the possibility of significant technical improvements in future technologies and practices, citing such technologies as incineration, recycling, and wet air oxidation. A careful review of the Report to Congress reveals that the only discussion of that conclusion in the body of the Report is contained on pages III-2 and III-3. That discussion however, offers no support for EPA's statements on page VIII-2 and instead, contradicts that conclusion. On page III-2, EPA states as follows:

> At least for the major high-volume streams, there are not significant newly invented, field-proven technologies in the research or development stage that can be considered "innovative" or "emerging."

EPA's conclusion that significant technical improvements in this area are foreseeable is purely speculative and not supported by any objective findings of the Report to Congress. This is a matter of particular concern in the Appalachian states because of the unique waste management practices that have evolved as a function of the careful balance which exists between environmental protection and economic realities of Appalachian wells. As the result, there is no basis for believing that any significant change in waste disposal practices is foreseeable in the Appalachian states.

Even something as relatively simple as the segregation of wastes suggested on page VIII-3 of the conclusion to EPA's Report to Congress, must be carefully examined for its application to Appalachian operations. It is essential that EPA continue to recognize that the complete segregation of exempt and non-exempt wastes is not feasible during normal operations. Small amounts of non-exempt material will necessarily become mixed with exempt wastes during these normal operations. If segregation of waste is appropriate at all, it should be limited to only the segregation of <u>unused</u> materials, such as pipe dope, motor oil, solvents, and similar materials and be directed towards assuring that these materials are not deliberately and unnecessarily disposed of in reserve pits. Even in those cases where the segregation of these limited materials is appropriate, we urge EPA to carefully review any regulatory requirements that might be imposed to assure that they are protective of the environment without being unnecessarily costly from either an

environmental control or an administrative viewpoint.

F. Existing State and Federal Regulatory Authorities Are Adequate to Prevent or Mitigate Adverse Impacts.

While the Appalachian Producers concur with EPA's conclusion [See Report to Congress, p.VIII-11], that the application of full, unmodified Subtitle C regulations to all exempt wastes appears unnecessary at this time, we are extremely concerned about EPA's recommendation that it is necessary to conduct a further review of state and federal programs with a view towards possible modification.

From our review of the Report to Congress and from our own assessment of the state regulatory requirements, at least for the seven Appalachian states involved, it is apparent that existing regulatory requirements, both state and federal, are more than adequate to prevent or mitigate any adverse impacts on the environment caused by the management of oil and gas drilling and production wastes. Nearly all of the damage cases cited by EPA in its Report to Congress would violate present day regulatory requirements should they occur today. In fact, most of the damage cases cited by EPA violated regulatory requirements at the time they occurred. In those cases where the damage case did not violate requirements that were in effect at the time the damage occurred, subsequent regulatory developments have consistently been implemented to address those concerns. In short, we have not identified any of the damage cases related to the Appalachian states that would not violate current regulatory requirements should they occur at the present time.

The most significant shortcoming in EPA's analysis of existing regulatory programs is it's apparent failure to recognize that these programs have evolved significantly in the last few years. In addition, major changes in state regulatory programs are underway at the current time. For example, an entirely new regulatory program has been proposed for adoption in Pennsylvania. In West Virginia, a new general permit for drilling fluids was issued in the last 60 days with efforts underway to issue a general permit addressing the handling of produced water. Moreover, each of the states has statutory authority which allows them to address virtually every aspect of the waste management practices of the oil and gas industry as the need to do so is identified.

We believe there can be no dispute but that existing state and federal regulatory requirements provide a full and exhaustive set of regulations already in place, along with the process to update and refine those regulations either now or in the future as the need to do so is identified. As will be discussed in greater detail later in these comments, this fact provides the basis for a decision not to impose any further regulatory requirements on Appalachian operators.

G. EPA's Risk Assessment Modeling Shows Negligible Impacts on the Environment.

While the Appalachian Producers do not necessarily agree with the appropriateness of conducting risk assessment modeling in the context of this study, we do share the conclusion

reached by EPA that if there were release of toxic chemicals, the risks would be "very small to negligible." See Report to Congress, p.V-64. We remind EPA, however, that the quantity of waste produced by Appalachian operations is much smaller than is produced in other regions of the country. We believe that the necessary result of this fact is that the risks related to these operations would be even smaller than EPA determined through its own analysis.

As we have pointed out elsewhere in our comments, a typical drilling pit capacity in the Appalachian states is less than 2,000 barrels and frequently is as small as 500 barrels. With respect to produced water, our survey of more than 17,000 primary production gas and oil wells indicates that nearly all of them produce less than one barrel of water a day. This data, submitted to EPA in our formal comments of February 10, 1987, also revealed that for gas wells, 39 percent of the wells produced no water at all and 90 percent of the wells produced 1/3 barrel of water per day or less. For oil wells, the survey results revealed that approximately 23 percent of the primary oil wells produced no water at all, while approximately 65 percent of those wells produced less than 1/3 of a barrel of water per day on average.

We urge EPA to recognize that these significantly lower quantities of waste being produced by Appalachian operations necessarily result in less environmental risk than was identified by EPA in its modeling.

H. EPA's Economic Impact Analysis Does Not Adequately Assess Cost Impact on Appalachian Operations.

While we share EPA's ultimate conclusion that the imposition of RCRA Subtitle C would have "a substantial impact on the U.S. economy" [See Report to Congress, p.VIII-9], we have significant concerns over EPA's economic analysis. Our concerns center around several areas in which EPA has understated the impact of imposing alternative requirements on the industry. As will be reviewed in this section, we believe EPA's economic analysis overstates baseline costs while understating the cost of alternative requirements. The end-result is a masking of the true cost of imposing alternative waste management practices on the industry. In addition, EPA has failed to properly assess the impact of these increased costs on the industry, particularly in the Appalachian states.

1. Overstated Baseline Costs.

At the heart of EPA's economic impact analysis is its determination of the current costs borne by the industry for the management of both drilling waste and produced water waste. The "baseline" cost of drilling waste management for the Appalachian zone, as reflected on page VI-26 of the Report to Congress, is $9,465. These costs are significantly greater than actual experience indicates to be the case in Appalachia. In part, this can undoubtedly be explained by EPA's erroneous assumption that 77 percent of all drilling pits in the Appalachian Basin are currently lined [See Report to Congress, p.VI-5]. Not only is this conclusion contrary to fact, it is

also refuted by the discussion on page VI-3 of the Report to Congress which points out that for drilling operations, wastes are typically stored in unlined surface impoundments during drilling and by the discussion appearing on page III-17 of the Report to Congress indicating that drilling pits are generally unlined. Because such a high percentage of drilling pits in Appalachia are assumed already to be utilizing liners, EPA's economic analysis assumes that those pits would not be affected by the Intermediate Scenario discussed in the Report. We urge EPA to revise it's analysis of the baseline drilling waste disposal costs in Appalachia to take proper account of the number of drilling pits that are currently lined and reflect the costs which are actually incurred currently in managing drilling wastes.

2. Understated Alternative Costs.

We are pleased to note on pages VI-11 and VI-13 of the Report to Congress that EPA has recognized it must take the cost of transportation and loading and unloading charges into account in determining the cost of Class II injection. Our detailed discussion of this factor was provided to EPA in our comments filed on June 13, 1987. We also commend EPA for it's recognition of the fact that injection wells in the Appalachian region are not capable of receiving the higher volumes of waste as are assumed with respect to the rest of the nation. Our detailed comments on the rate of injection that could be expected in the Appalachia were also included in our June 13, 1987 comments.

Nevertheless, we recognize, as does EPA on pages VI-3 and VI-17 of the Report to Congress, that EPA's cost impact analysis does not reflect all of the costs that would result from the imposition of RCRA Subtitle C regulation. In particular, we note that EPA has not taken account of the costs that would be associated with satisfying the land ban and corrective action requirements of the Hazardous and Solid Waste Amendments of 1984. If these costs had been considered, the true economic impact of alternative scenarios would have been astounding.

In addition, for reasons stated in the preceding paragraph, EPA has failed to properly identify the true costs of alternative requirements because they have overstated the baseline costs associated with waste management in the industry.

3. <u>Understated Economic Impact.</u>

EPA's Final Report to Congress has done little to address our earlier concerns about it's methodology to assess the impact of the costs of alternative waste management techniques. In particular, we note that on page VI-22 of the Report to Congress, EPA assumes the wellhead price of oil to be $20.90 per barrel in the Appalachian region. This is significantly above the current wellhead price of oil in the region which is as low as $14.50 per barrel. Using such an inflated oil price results in a rate of return for new projects which is much higher than actually occurs. EPA's analysis does, therefore, mask the true impact of the resulting cost increases.

Beyond direct impacts on individual wells, EPA must recognize the impact which any cost increases would have on

the entire Appalachian region and on the nation. The enormous plugging liability and lost production caused by new regulatory requirements will not only be felt by oil and gas companies, but also by thousands of investors, land owners with royalty interests, service companies, support industries, regulatory agencies, tax revenues at all levels of government, and finally by the consumers of oil and gas products. In addition, regulatory requirements would also directly impact on the nation's balance of trade because of additional oil imports. The impact of such requirements on the nation's natural gas supply would also be disastrous and would result in shortages of natural gas available to heat homes, schools and businesses and a dramatic increase in price for such natural gas that remained available.

EPA's economic analysis is further defective because it does not recognize that a waterflood or EOR project does not begin production for at least 2 years after initial investment is made. This significantly reduces the economic rate of return of those projects. This is especially significant since over 40% of the nations crude oil is produced by this method.

We also find it incredible that EPA could have conducted its cost impact analysis by examining only the closure of oil wells. In Appalachia, 53% of the successful wells are gas wells. The significance of these wells to the region is very large and the failure by EPA to have modeled the closure of the wells is a major defect of the study.

Many additional concerns about EPA's economic analysis are contained in our comments filed on June 13, 1988. EPA is encouraged to examine these comments for discussion of such issues as cost of capital, hurdle rate, and internal rate of return.

4. Appalachian Impacts.

Perhaps the most serious criticism of EPA's economic impact analysis is that it lacks the sensitivity that is necessary to determine to the impacts of very small cost increases on Appalachian Producers. EPA has examined three alternative scenarios for purposes of assessing economic impact. As flawed as they may be, the studies which EPA performed on each of these analyses clearly indicates the devastating impact that they would have on Appalachian operations.

EPA's analysis should not stop, however, with examination of these three alternatives. If EPA is truly interested in considering the possibility of development of alternatives under RCRA Subtitle D, the Safe Drinking Water Act, or the Clean Water Act, it must be prepared to assess the cost impact of those alternative on the Appalachian region.

In performing this analysis, EPA must understand that objectionable cost impacts on Appalachian Producers would not only result from the imposition of hazardous waste regulations, but also from the imposition of new regulatory requirements under any program. Moreover, EPA must recognize that any increase in capital or operating costs in the Appalachian region would have a much greater impact on the

economic viability of those operations than might be the case elsewhere in the nation. From data we submitted to EPA in February, 1987, it is apparent that nearly all producing wells in the Appalachian region are stripper wells. Wells that were not stripper wells initially, become stripper wells after only a year or two of production. In other words, Appalachian wells are extremely sensitive to any increase in capital or operating costs. For example, a $200 increase in operating costs experienced by the region's approximately 200,000 existing wells would force nearly 20 percent of those wells to be plugged and abandoned. A $2,000 per year increase would cause nearly half of these wells to become uneconomical and to be plugged and abandoned. These illustrations point out the marginal nature of most of the production under current business conditions.

To take this thought process a step further, if additional hazardous or non-hazardous regulations caused only a $2,000 increase in operating costs each year, nearly 96,000 wells would have to be plugged in the Appalachian Basin states at a cost of approximately $960,000,000 for direct plugging costs alone. Approximately 92 BCF of natural gas production and over 11,000,000 barrels of oil production would be lost each year from existing wells alone. The expected returns on investment in future wells to be drilled would drop several percentage points as a result of the $2,000 increase in annual operating costs and several points because of a corresponding increase in drilling costs. This means that a large percentage of wells that might have otherwise been economical to drill would not be drilled

because of these additional regulatory costs. Even the wells that were still economical to be drilled would have a shortened production life because of the additional costs. Of the 15,000 to 20,000 wells that would otherwise be drilled each year in these seven Appalachian states, thousands would never be drilled.

Costs that might otherwise seem insignificant to wells with a stronger economic basis become matters of major concern for Appalachian wells. EPA's current economic impact analysis is simply insensitive to these types of impacts and EPA should make independent inquiry into the cost impacts of non-hazardous waste regulatory programs prior to making them applicable to any Appalachian wells.

I. There is No Justification for New Hazardous or Non-hazardous Waste Regulations as a Result of EPA's Study.

As discussed in previous comments, EPA's Report to Congress has concluded that existing state and federal regulatory programs are adequate to prevent or mitigate adverse impacts on the environment. The Report to Congress also has identified the severe economic impacts that would be realized by the oil and gas industry in general should hazardous waste regulatory requirements be imposed. These factors, in combination with EPA's failure to identify significant unregulated environmental risks, compel the conclusion that no further regulatory requirements are appropriate.

The legislative history related to this study is enlightening in explaining the thought process that EPA is

expected to follow in conducting the study and the rulemaking decisions that will necessarily follow it. In this regard, the Senate Committee on Environment and Public Works stated:

> The committee determined that the extensive regulatory program proposed by the Agency [RCRA Subtitle C] could have significant economic impact on domestic oil and gas exploration and production activities. Therefore, regulations on these materials should not be promulgated until further information is developed to determine whether a sufficient degree of hazard exists to warrant additional regulations and whether existing State and Federal programs adequately control such hazards.

S. Rep. No. 96-172, 96th Cong. (*reprinted in* 1980 U.S. Code Cong. & Ad. News 5019, 5024-25).

Additionally, the Senate Committee offered the following description of the intent of the study:

> The thrust of the study is to determine the degree of hazard associated with these wastes, the adequacy of the existing State and Federal regulatory programs to control and mitigate any hazards, potential changes to regulatory programs to improve control and mitigation of hazards; and the cost impact of those changes on the exploration, development and production of crude oil and natural gas.

Id. at 5026.

These statements are particularly instructive in understanding Congressional intent because it was the Senate bill which was adopted in lieu of the House bill when Congress passed the Solid Waste Disposal Act Amendments of 1980.

For the Appalachian Producers, the concerns expressed by this legislative history are brought into even sharper focus. In the Appalachian states, perhaps more so than anywhere else in

the nation, it has been necessary for regulatory programs to be developed in close concert with the hard economic realities of oil and gas operations. These regulatory requirements have been carefully crafted by each of the Appalachian states to take account of the climatology, hydrology and geology of each area, as well as the economic costs that would be imposed by those requirements. Changing this balance by imposing minimum national standards has the potential to create significant economic dislocation in this region.

EPA's recommendation [See Report to Congress, p.IX-1], that minimum requirements may be based on RCRA's Subtitle D, the Clean Water Act's NPDES program, or the Safe Drinking Water Act's Underground Injection Control Program offer little comfort to the Appalachian Producers. Whether a new regulatory requirement is based upon hazardous waste regulatory authority or any other regulatory authority, the impact on the operator will be the same. As discussed in our previous comments on economic impact, even a few hundred dollars of increased costs each year will cause a very significant number of Appalachian wells to be plugged and abandoned.

Accordingly, we do not believe that it is necessary or appropriate for any new regulatory requirements to be imposed on any segment of the oil and gas industry. We do, however, support the recommendation by EPA that efforts be undertaken to develop cooperative approaches with the states that would explore non-regulatory support for current programs in the form of funding, training, or technical support.

J. EPA Should Create a Special Subcategory to Address Characteristics of Appalachian Operations.

As stated above, the Appalachian Producers, do not believe that it is necessary or appropriate for any new regulatory requirements to be imposed on the oil and gas industry. Should EPA, nevertheless, be inclined to pursue the development of new regulatory requirements in response to this study, we submit that the circumstances surrounding operations in the Appalachian states justify exempting these operations from any new regulatory requirements.

There are three principal bases upon which an exemption for the Appalachian states should be considered:

(1) The nature of the waste streams involved;

(2) The adequacy of existing regulatory programs; and

(3) The cost impact of alternative requirements.

With respect to the nature of the waste streams involved, we have pointed out in these and other comments that very much smaller quantities of waste are produced by Appalachian operations than are produced elsewhere in the nation. This is true both with respect to produced water and with respect to drilling fluids. Beyond distinctions based on quantity, Appalachian wastes are different because most drilling is conducted without using drilling muds. Air drilling, as it is called, produces very small quantities of waste that have properties reflecting very low toxicity. Where it is necessary to use liquids in the drilling process, those liquids are generally created by combining water with small amounts of

potassium chloride, a material frequently used in agricultural fertilizers.

The regulatory programs applicable in the Appalachian states have been custom made to deal with the particular environmental objectives of the states involved. Since evaporation and underground injection are not readily available, alternative requirements, such as land application, stream discharge, annular disposal, and roadspreading, have been developed. These programs are working well and are serving to adequately prevent or mitigate adverse effects on human health and the environment.

Finally, EPA must recognize that if it were to require alternative waste management practices to be imposed on Appalachian operations, the impact of cost increases that might otherwise seem insignificant to operations with stronger economics would be devastating to Appalachian operations. This impact would be greatly magnified throughout the Appalachian states because 97 percent of all primary production oil and gas wells in the region are stripper wells. It is also significant that 57 percent of all primary production oil wells produce less than 1 barrel of oil per day.

The combination of these three factors compel the conclusion that the current regulatory and waste management requirements in Appalachia should not be altered as part of the establishment of any national environmental regulatory program. Should there be the need to consider refinements in any of these state programs, we submit that the state regulatory agencies

involved have adequate statutory authority to refine their regulations, permits, and programs in a way appropriate to address the need. We also submit that it is at the state level that the expertise exists to fashion an appropriate regulatory program addressing whatever environmental concerns may exist with respect to waste management practices of the industry, along with a recognition of the economic capabilities of those operations.

IV. Regulatory Alternatives.

Notwithstanding the inherent problems with EPA's Report to Congress, our review of this document leads us to believe that the Agency has three options available to it which will result in a different regulatory process as it affects oil and gas drilling and production wastes studied in the Report to Congress.

The only aspect of the court order remaining with which EPA must comply is the June 30, 1988 date for the determination by the EPA Administrator of whether or not, if at all, to impose hazardous waste regulation on any of the oil and gas wastes studied under Section 8002(m). Notwithstanding the fact that this determination is inherently tied to the scope of the exemption and the wastes studied, a concept previously discussed in these comments, EPA may make the following decisions on June 30.

(1) On June 30, 1988, EPA may make a decision that no regulation of any kind is necessary for certain oil and gas drilling and production wastes. If so, the question is then raised as to how this determination will be reflected in the

statute and regulations. EPA might consider the promulgation of regulations stating that no regulation of oil and gas drilling and production wastes is necessary. This has the effect of maintaining the exemption from Subtitle C regulation in the Agency's hazardous waste administrative regulations. EPA might also choose to stand silent on the issue, which has the effect of leaving the statutory exemption intact for oil and gas drilling and production wastes. We strongly urge EPA to consider, under this scenario, the latter course of action--that is, the maintenance of a statutory exemption for oil and gas drilling and production wastes from Subtitle C regulation.

(2) As part of its June 30, 1988 decision regarding regulation, EPA may make a decision that certain wastes should be regulated under one or more of its presently existing non-hazardous wastes programs. Any such process would involve the development of significant new regulations under those programs and would require the requisite time for the development, proposal, finalization, and implementation of these regulations. As has been the case throughout the study process, the Appalachian Producers will continue to be significantly involved in the development of this program, if any, in the form of commenting, as they have in the past, on various Agency proposals.

(3) The possibility exists that pursuant to its June 30, 1988 determination, EPA might decide that Subtitle C hazardous waste regulation of certain oil and gas drilling and production waste is, in fact, necessary. The scenario regarding

development of any Subtitle C regulations would be similar to that as discussed above with the exception that such regulations would have to be submitted to Congress pursuant to present statutory authority for their ultimate approval.

Again, it is the position of the Appalachian Producers that no such regulations are necessary and that adequate state and federal regulatory authority already exists to handle any environmental problems of the industry. It is our belief that after competent review of existing state and federal regulatory authorities and disposal practices employed in the Appalachian region, the inalterable conclusion must be that neither Subtitle C nor any other type of new regulation is necessary.

V. CONCLUSION.

That portion of EPA's study of oil and gas drilling and production wastes under RCRA ordered to be done by a federal district court has been completed with EPA's submission of its Report to Congress on December 31, 1987. There are a myriad of erroneous assumptions, facts, statements, and conclusions contained in this Report. These errors have been addressed in these comments, as well as the previous comments submitted by the Appalachian Producers which have been incorporated by reference into these comments. We urge EPA to address these errors and deficiencies prior to making its regulatory determination in this matter.

Respectfully submitted this 14th day of March 1988.

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PENNSYLVANIA OIL AND GAS ASSOCIATION
TENNESSEE OIL AND GAS ASSOCIATION
VIRGINIA OIL AND GAS ASSOCIATION
and the
WEST VIRGINIA OIL AND NATURAL GAS ASSOCIATION

Exhibit A

United States Senate

COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
WASHINGTON, DC 20510-6175

November 17, 1987

The Honorable Lee M. Thomas
Administrator
U. S. Environmental Protection Agency
401 M Street, S. W.
Washington, D. C. 20460

Dear Mr. Thomas:

As the deadline approaches for the submission of EPA's Report to Congress on oil and gas waste pursuant to §8002(m) of the Resource Conservation and Recovery Act ("RCRA"), it becomes increasingly important for EPA to complete its identification of the wastes that are properly includable in the study. It is these wastes that EPA and Congress must address in determining whether to impose hazardous waste regulations pursuant to Subtitle C of RCRA.

I am sure you recognize that a decision at this time to include a waste within the study would not exempt that waste from hazardous waste regulation permanently. Instead, such a decision would simply continue the exemption in effect until such time as Congress determines it to be appropriate to impose hazardous waste regulation on that waste.

A review of §8002(m) of RCRA and the legislative history associated with that section reveals the clear intent of Congress that the scope of the study be broadly interpreted to include all drilling fluids and produced waters wherever they occur as well as associated wastes intrinsically derived from primary field operations. Given this Congressional intent, I urge you to include within the study the broadest possible scope of wastes associated with this industry.

I look forward to receipt of your Report to Congress on this important issue.

With kind regards, I am

Sincerely,

Quentin N. Burdick
Chairman

QNB;pp;jc

O GRA - SO - 597

**COMMENTS REGARDING THE APRIL 30, 1987,
INTERIM REPORT
OF THE
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WITH RESPECT TO WASTES FROM THE
EXPLORATION, DEVELOPMENT AND PRODUCTION OF CRUDE OIL,
NATURAL GAS AND GEOTHERMAL ENERGY**

ON BEHALF OF THE

INDEPENDENT OIL AND GAS ASSOCIATION OF NEW YORK
INDEPENDENT OIL AND GAS ASSOCIATION OF WEST VIRGINIA
KENTUCKY OIL AND GAS ASSOCIATION
OHIO OIL AND GAS ASSOCIATION
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VIRGINIA OIL AND GAS ASSOCIATION
and the
WEST VIRGINIA OIL AND NATURAL GAS ASSOCIATION

SUBMITTED BY:

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June 13, 1987

COMMENTS REGARDING THE APRIL 30, 1987, INTERIM REPORT OF THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY WITH RESPECT TO WASTES FROM THE EXPLORATION, DEVELOPMENT AND PRODUCTION OF CRUDE OIL, NATURAL GAS AND GEOTHERMAL ENERGY

On April 30, 1987, the United States Environmental Protection Agency ("EPA") issued an Interim Report in connection with the preparation of the Report to Congress mandated by §8002(m) of the Resource Conservation and Recovery Act ("RCRA").

These comments are being filed with respect to that Interim Report on behalf of the following trade organizations representing oil and gas operators in the Appalachian Basin:

Independent Oil and Gas Association of New York
Independent Oil and Gas Association of West Virginia
Kentucky Oil and Gas Association
Ohio Oil and Gas Association
Pennsylvania Natural Gas Associates
Pennsylvania Oil and Gas Association
Tennessee Oil and Gas Association
Virginia Oil and Gas Association
and the
West Virginia Oil and Natural Gas Association

CHAPTER 1 - OVERVIEW OF THE OIL AND GAS INDUSTRY.

1. The Nature of Drilling Pit Waste.

On page I-12, and again on page I-22, it is reported that drilling pits receive sewage or sanitary waste. On page I-22, the statement is also made that the pits receive waste lubricants, waste hydraulic fluids, waste solvents and waste paints. These situations do not generally occur in the Appalachian Basin. For example, under the terms of the drilling

waste general NPDES permit issued by West Virginia (WV0073343), the discharge of such material to a drilling pit is expressly prohibited.

2. Stripper Wells.

On page I-49, the statement is made that 70% of the total oil wells in the United States are "stripper oil wells" and that marginal gas wells correspond to stripper oil wells. This statement is not accurate for the Appalachian Basin where stripper oil wells and stripper (or marginal) gas wells exists at a much higher percentage. As reported in the document filed by these commentors with EPA on February 10, 1987, entitled "An Analysis of the Economic Impact of New Hazardous Waste Regulations on the Appalachian Basin Oil and Gas Industry" a survey of more than 17,000 gas and oil wells in the Appalachian Basin reveals the following results:

Type of Well	Percent Stripper
Oil	98.2
Gas	92.1

These results assume stripper oil wells defined at less than 10 barrels of oil per day and stripper gas wells defined at less than 60 MCF per day.

3. The Quantity of Drilling Waste.

With respect to the seven states represented by these commentors, EPA has made the assumption that 90% of all drilling pits in those states would be small with a capacity of 1,984 barrels. The other 10% of the pits are assumed to be of medium size with a capacity of 22,700 barrels. With these basic assumptions,

EPA has then calculated the total estimated waste generated in each state as a variable of the number of wells drilled in each state for calendar years 1981 through 1985. These assumptions are erroneous as to these Appalachian Basin states where less than 1% of wells drilled each year would utilize pits of the capacity of 22,700 barrels. The remainder of the pits (greater than 99%) would be of the smallest size with many of such pits having a capacity of less than 1,000 barrels.

4. The Quantity of Produced Water.

EPA used three different methods to determine the quantity of produced water generated each year in the Appalachian Basin states. First, with respect to Kentucky and West Virginia, the produced water was estimated from water/oil ratios from surrounding states. Second, with respect to New York and Ohio, produced water was estimated from water/oil ratios from years for which there is actual data available from those states. And third, for the states of Tennessee and Pennsylvania, estimates were calculated by specific methodologies set forth in Table I-8. Our review of these estimates indicated that only the values for New York and Ohio appear to be reasonably accurate.

The values for Kentucky appear to be reasonable for primary oil production but not reasonable for enhanced oil recovery which may be significantly greater. The values for Pennsylvania, on the other hand, are much higher than are actually experienced.

EPA should rely only on data derived from a state to estimate that state's produced water. The results of a survey of

nearly 20,000 wells in the Appalachian Basin to determine the amount of produced water from those wells was submitted to EPA by us on February 10, 1987.

CHAPTER 2 - CURRENT AND ALTERNATIVE PRACTICES.

In this section, we note that EPA has limited its data base to 13 of the oil and gas well-producing states in the belief that an examination of these states will be representative of all of the oil and gas-producing states in the nation. As it relates to the Appalachian states, EPA includes material with respect to Ohio and West Virginia. Our comments will, therefore, be limited to the regulatory requirements of these two states.

1. Trash Disposal in Drilling Pits.

On page 17, EPA states that reserve pits are used to dispose of trash, waste lubricating oils, waste chemicals, diesel fuel, and pipe dope. EPA's attention is called to the West Virginia drilling waste general permit (WV0073343) which expressly precludes this act.

2. Drilling Pit Siting and Construction.

On pages 19 and 20, EPA describes environmental problems relating to the leaching of pollutants from drilling pits to ground water and erroneously concludes that there is "currently little emphasis at the State level on reserve pits siting and monitoring requirements."

Both Ohio and West Virginia have expressed statutory prohibitions against the leaking of drilling pits to either surface or subsurface water. In addition, both states have

specific regulatory requirements which not only prohibit the leaking of drilling pits but which also establish specific requirements for the construction and maintenance of drilling pits. The West Virginia general permit for oil and gas well drilling operations also contains specific requirements with respect to the siting and construction of drilling pits. In Ohio particular emphasis is given to drilling pits in the Lake Plains Region where synthetic liners or steel tanks are required to contain drilling wastes.

The correct conclusion is that regulatory programs and industry practices in Ohio and West Virginia place great emphasis on drilling pit siting, construction and monitoring.

3. Land Application of Drilling Waste.

Beginning on page 32 and continuing through page 36, EPA offers a description of various regulatory issues associated with the land application of drilling fluids. In that discussion, EPA places considerable emphasis on the regulatory requirements which are applicable to land application of drilling fluids in West Virginia. In addition to discussing generally the regulatory requirements in West Virginia, EPA identifies two matters of concern to it (1) the regulation of chloride, and (2) the absence of specific discharge limits on heavy metals and toxic materials.

The general NPDES permit for the disposal of drilling fluids in West Virginia was issued on July 10, 1985. That permit, the first of its kind in the nation, established a mechanism by which an operator was obligated to construct

drilling pits, treat the contents of those drilling pits, and dispose of the contents either by land application or by off-site disposal. While the permit contained specific discharge limits only for chloride, pH and total iron, those limits were developed to serve as surrogates for limitations on a variety of other parameters. In addition, the fact sheet supporting that general permit recognized that by specifying a particular type of treatment required on each pit (aeration, pH adjustment, mixing and settling), it would not be necessary to regulate a number of other parameters, particularly organics. In short, the West Virginia general permit uses a combination of discharge effluent limitations and specified treatment requirements to achieve appropriate objectives. With respect to chloride, the effluent limitation was set at 25,000 mg/l recognizing that drilling pits in West Virginia typically contain between 500 and 2,000 barrels of fluid which would be applied to land on a one-time basis.

These permit conditions were presented to EPA for review in advance of permit issuance and by letter dated July 9, 1985, from the Director of the Water Management Division of U.S.EPA's Office, the West Virginia Department of Natural Resources was advised that EPA did not object to the land application of these wastes "if accomplished in accordance with the proposed permit conditions." In addition to this endorsement by both the state and EPA, the chloride discharge limitation has proven to be effective in protecting the environment in the nearly two years that the general permit has been in effect. During that time period there have been more than 1,300 cases in

which drilling pit fluids have been discharged without problem. As will be discussed later in connection with EPA's damage cases, there was one situation in which vegetation was temporarily stressed as the result of a land application conducted under the general permit (WV13). Investigation into that incident revealed the potential for a number of factors contributing to that stress with no definitive conclusion reached as to whether chloride at the discharge level of 18,000 ppm was the cause of that stress. There have been a number of instances of land application of drilling fluids under the general permit in which the chloride concentration exceeded that amount.

In the second round of the drilling fluids general permit proposed for public comment on May 29, 1987, additional restrictions on chloride discharge have been proposed. Pursuant to the proposed permit the chloride discharge limitation would become 12,500 ppm and the amount of drilling fluid that could be land applied would be limited to 20,000 gallons per acre per day. The chloride limit has been reduced largely because experience has indicated that such a lower limit can be achieved in most cases and to eliminate any question about the appropriateness of the initial permit to address adverse chloride impacts on vegetation. The second round general permit would also establish final effluent limitations for dissolved oxygen, total suspended solids and total manganese and would establish a monitoring program leading to the establishment of an effluent limitation for total organic carbon in September, 1988.

In summary, it has been the experience of both operators and regulatory agencies that the general permit for drilling fluids in West Virginia has proven to be an extremely effective regulatory vehicle by which to assure an environmentally acceptable means of disposing of drilling fluids.

4. Annular Disposal of Produced Water.

On pages 55 and 59, EPA offers comment on the use of annular disposal for produced water. EPA observes that annular disposal is not a widespread practice and has a higher potential to contaminate fresh ground water.

Annular disposal is a practice which is of great significance and benefit to Ohio where the comprehensive regulatory program has been established to assure that annular disposal is conducted in an environmentally acceptable manner. Ohio's annular disposal regulations are set forth at OAC §1501:9-3-11. Those regulations provide that the disposal of saltwater into the annular space of any well is prohibited except where approved by the Division in accordance with established regulations. Those regulations require that any well authorized to use annular disposal be constructed such that the surface casing is sealed with cement, prepared clay or other material.

In addition, all systems must be air tight. As reported by Elmer E. Templeton & Associates in a report to the Ohio Water Development Authority dated January, 1980, entitled "Environmentally Acceptable Disposal of Salt Brines Produced with Oil and Gas" an air tight system is necessary to eliminate dissolved oxygen which would contribute to pipe corrosion.

Annular disposal in Ohio is not conducted with artificial pressure and, instead, it relies on gravity.

It has been the experience of operators and regulatory agencies in Ohio that when annular disposal is conducted in accordance with the regulations of the Ohio Department of Natural Resources, it is an environmentally acceptable means of disposing of produced water.

5. Surface Stream Discharge of Produced Water.

On page 68, EPA identifies only two cases in which discharges to surface water bodies are to be recognized:

(1) coastal or tidally influenced waters; and

(2) agricultural and wild life categories.

Conspicuously missing from this description is the category recognized under EPA's effluent guidelines set forth at 40 C.F.R. Part 435 with respect to the discharge of produced waters from stripper oil wells. West Virginia is now preparing a general permit for the stream discharge of produced water from stripper oil wells which is expected to be issued during the second half of 1987.

6. Plugging Requirements.

In its discussion of plugging requirements on pages 75 and 76, EPA makes the statement that while most states seek to protect upper fresh water zones in well plugging, West Virginia protects only coal strata. To the contrary, W.Va. Code §22B-1-24(a) sets forth specific plugging requirements that deal with wells that do not penetrate workable coal beds.

CHAPTER 3 - OIL AND GAS DAMAGE CASES.

At the outset, we must express our concern (and surprise) that EPA has a stated intention to examine damage cases outside the scope of RCRA §8002(m)(C). This point is, however, expressly made by EPA on pages 1 and 2 where the purposes of the damage case review are identified to be:

- To respond to the requirements of §8002(m)(C);
- To provide an overview of the nature of damages associated with oil and gas exploration, development, or production activities.

Although the report contains a statement indicating that damage cases falling into the second category are excluded from the report, it is apparent that such has not occurred. As will be seen from a detailed review of the discussion particularly with respect to Zones 2 and 5, the report contains extensive discussion of such issues as erosion control practices, surface owner rights, and the intentional use of pits by landowners for the watering of domestic animals, each of which are matters not related to the mandate of RCRA §8002(m).

Before turning to specific comments contained in this chapter with respect to the Appalachian Basin states, we will first address EPA's general conclusions.

A. General Conclusions.

Beginning on page 5, EPA, very appropriately, identifies a number of factors which limited its study and its results. These limitations included:

- the limited time period for the study;
- the failure to examine some of the oil and gas producing states;
- the sampling of damage cases was not necessarily representative (as with the State of Ohio, the number of cases involved may have been influenced by the ease with which the data was made available to EPA's contractor);
- EPA's discussion of applicable laws was not complete; and
- effects of recent oil price declines were not fully analyzed.

The Interim Report simply ignores these limitations, however, in arriving at nine general conclusions.

An earlier effort was undertaken by another EPA contractor; however, we have not been provided with an opportunity to review the findings and conclusions of that contractor on the damage cases identified by that contractor.

1. Health and Environmental Damages Caused by Oil and Gas Operations Appear to be Significant, Widespread, and in Need of Correction.

This conclusion, stated on page 8, is offered without support or justification. To the contrary, a review of the damage cases identified by the agency reveal that the regulations and industry practices which govern environmental protection in the oil and gas industry have become increasingly effective. Regulatory programs have evolved addressing each of the concerns that EPA identified in its review of historical damage cases. Where adjustments in regulatory programs were necessary, those adjustments were made in the context of existing state or federal programs.

2. There is Convincing Circumstantial Evidence that Serious Health Effects, Such as Cancer and other Fatal Diseases, Have Been Caused or are Potentially Caused by Oil and Gas Activities.

Of all of the statements in the report, this one is by far the most inflammatory and least supported. Moreover, the damage case analysis mandated by RCRA §8002(m)(C) calls for the identification of cases "that prove or have caused" danger to human health and the environment. There being no legal or factual basis for this statement, it should be stricken from the report.

3. Damages Are Caused By Nonhazardous As Well As Hazardous Substances.

The discussion of this issue fails to disclose that the 250 ppm human health consumption standard for chloride in drinking water is not set to protect public health but, rather, is set as a taste threshold. In addition, there is no basis apparent in any of the analytical data taken by EPA that drilling muds or their constituents are hazardous by one or more RCRA definitions. This is certainly not the case in connection with Appalachian Basin operations where air drilling is predominantly used.

4. Past Practices Can Cause and Contribute to Current Damages.

This discussion misses the entire point of the regulatory process with respect to which this report is offered. The cases cited in support of this conclusion are cases in which wells were plugged or abandoned using techniques which would violate current-day regulatory requirements. To the extent that past regulations or industry practices resulted in damage cases, that issue has been addressed by current-day regulations and

practices eliminating the need for consideration of those damage cases in determining whether to adopt regulations pursuant to Subtitle C of RCRA.

5. State Standards Vary Widely in Scope and Content.

EPA has based this conclusion on its review of damage cases which have occurred over 20 years. The conclusion is not based on a review of current-day regulatory requirements of the various states. As the Interim Report itself recognized, EPA's review of current regulatory programs was not available when the Interim Report was prepared. If EPA's desire is to assess current state standards, it should do so by examining current day regulations and not historical damage cases.

6. Implementation and Enforcement of States Requirements is Serious Deficient.

On page 12 the Interim Report criticizes states for failure to implement and aggressively enforce their regulations. To understand the fallacy of this conclusion, one need only examine the damage cases related to West Virginia where, of the 14 cases that are relevant to RCRA §8002(m), criminal charges were brought against operators in 10 of those cases and, in two other cases, casing programs or land application requirements were modified to address the specific fact situation raised by those cases. In Ohio a nearly identical situation exists in which notices of violation were issued against operators for nearly all of the cases relevant to this study.

7. State Regulatory Programs are, as a Rule, Seriously Underfunded and Understaffed.

While state regulatory programs can always be improved by greater funding and greater staffing, we believe that an

objective review of the damages cases identified by EPA indicates that there is sufficient funding and staffing to assure an adequate level of enforcement.

8. Many State Regulatory Agencies Face Conflicting Incentives and Responsibilities.

There is no documentation apparent from our review of this chapter to support this statement. The level of enforcement and regulation that is apparent from a review of the damage cases growing out of the Appalachian states suggests that no such conflicting incentives or responsibilities exist to an extent that would undermine the credibility of enforcement.

9. In Some States Economic Reliance on Oil Industry Revenues Increases Public Tolerance of Environmental Damages.

As with several of the preceding points, there is no documentation in the Interim Report for this conclusion. Any objective analysis of the damages cases identified in this report indicates that the regulatory agencies have undertaken timely and appropriate enforcement of regulatory requirements against operators that violated them.

B. Zone 2 Conclusions

At the outset these comments it is appropriate to inquire as to the basis for EPA's definition of the states which should be included within Zone 2. Based upon earlier discussions with EPA we had what was believed to be a clear understanding that it was appropriate to include the State of Ohio within Zone 2 in order to give Zone 2 a scope which more nearly matched the Appalachian Basin. EPA considered Ohio to be within the scope of Zone 2 in its January 31, 1987 technical report of analytical

results and consider this to be the case in the economic section of the April 30, 1987, Interim Report. We urge EPA to include Ohio within Zone 2 for purposes of future reports.

We also note with interest the statement that most of the states within Zone 2 (New York, Pennsylvania, Delaware, Maryland, New Jersey, Virginia, West Virginia, Kentucky and Tennessee) have minimal oil and gas production. While it is true that some of these states produce almost no oil and gas and that the total production of all of these states is small in comparison with the national production of oil and gas, such production as does exist results in significant economic benefits in terms of employment, investment capital, tax revenues and royalties. Moreover, even though the Appalachian states (including Ohio) have only 1.2% of the Nations oil production it contains 14.2% of the oil wells. With respect to gas the Appalachian Basin has 3.1% of the gas production with 44.3% of the gas wells. Beyond the mere quantity of oil and gas produced, EPA should recognize that this region produces some of the highest quality lubricants in the world. In addition, the natural gas produced in the region is valuable beyond its volume because it is located near the major consumers of natural gas and, therefore, is not subject to transportation related restrictions.

1. Illegal Dumping of Brine, Drilling Mud, and Fracing Fluid.

In support of this conclusion EPA relies on three damage cases (WV18, WV20 and PA02 (sic)) and draws the general conclusion that the regulations either are not enforced or that

operators intentionally elect to pay fines rather than to comply with regulatory requirements.

While it is true that damage cases WV20 and PA02 (actually PA01) are cases in which operators were found to be in violation of state regulations prohibiting the disposal of waste in surface streams, these cases certainly cannot be cited in support of the general proposition that operators would prefer to violate rather than comply with the law. It is largely because of cases such as this that efforts were initiated in 1983 to urge EPA to revise its zero discharge effluent guideline to allow states such as West Virginia and Pennsylvania to establish requirements that would call for an operator to treat and discharge a pit to surface streams in a matter that would satisfy requirements of the Clean Water Act and assure compliance with water quality standards. In the meantime both West Virginia and Pennsylvania have demonstrated in the two cases involved that they will vigorously enforce the existing zero discharge requirement until it is revised by EPA.

With respect to the damage case WV18 EPA has inappropriately relied on this case as an illustration of environmental damage resulting from waste disposal practices associated with the exploration, development or production of crude oil or natural gas. In fact this case is one in which the operator was requested by a land owner to leave a pit in place so that it might be used as a source of water for livestock. This case certainly does not reflect industry practice and it should not be

relied upon as indicative of the manner in which waste are managed in the oil and gas industry.

Any objective examination of the damage cases identified by EPA in Pennsylvania and West Virginia indicates the strict level of enforcement that was adhered to by the state regulatory agencies. In West Virginia, 10 out of the 14 cases relevant to this study resulted in criminal actions being filed against the operator. The Pennsylvania cases reveal a similarly aggressive enforcement record.

2. <u>Damage to Water Wells after Gas or Oil Well Fracturing.</u>

In support of this conclusion the interim report relies upon three cases (WV02, WV17 and PA08) and a general concern that West Virginia has no regulation or statute that automatically requires an operator to replace a water well that has been damaged by oil and gas operations.

With respect to WV02 EPA has incorrectly determined that the ~~water well contamination~~ involved related to oil and gas operations. An investigation by a geologist of the West Virginia Department of Natural Resources determined that the contamination involved related to natural levels of contaminant in the aquifer that had been aggravated by surface coal mining operation. The details of this investigation are contained in our comments on EPA's summary of this case filed under separate cover. Moreover, the gas wells involved were more than 10,000 feet from the water wells that were alleged to have been contaminated.

With respect to WV17, our more detailed comments filed with respect to this case on June 11, 1987, indicated that

I have called both Atty for plaintiff & Dave Flannery to reconcile conflicts DS 7/14/87

neither the operator nor the regulatory agency were aware of the existence of a water well at the depth involved and that subsequently the state agency revised its casing requirements to require the installation of significantly more surface water casing.

With respect to PA08 an operator, no longer in business, apparently did contaminate certain water wells but was required to provided temporary water and to construct a new water system for those whose wells had been affected.

Finally, as to EPA's general concern that West Virginia has no provision for automatically requiring drillers to replace water wells, we suggest that the presence or absence of such a provision is not relevant to this study. Even though not relevant, it is a fact that surface owners are given considerable opportunity to be involved in the siting of wells and drilling pits. West Virginia's general permit for drilling fluids (WV0073343) requires that the surface owner be given notice of the intent to drill and be given an opportunity to object to any aspect of that operation that would give rise to water quality concerns.

3. Inappropriate Land Spreading Requirements in West Virginia.

The chloride effluent limitation obtained in the current drilling fluids general permit is a condition that was originally approved by EPA as being appropriate at the time the permit was issued. In the nearly two years that the general permit has been in place there has been more than 1,300 land applications which have been successfully accomplished. In only

one case was there evidence of even temporary vegetation stress. This point is further mitigated in the second round general permit for drilling fluids to be issued in July 1987 for a five year period where the chloride limit will be reduced even further to 12,500 ppm and a condition imposed which restricts the application of drilling fluids to 20,000 gallons per day per acre.

With respect to the case relied upon by EPA in support of this conclusion (WV13) it should be noted that it was not possible to determine whether it was the chloride concentration alone which caused the vegetation stress. In any case the vegetation did not die and instead recovered fully in about two weeks. A number of land applications have taken place successfully with chloride concentrations in excess of that which existed in case WV13.

4. Illegal Discharge of Oil.

EPA relies on damage case PA09 in support of this conclusion. That case involves the action of EPA and the U.S. Coast Guard under Section 311 of Clean Water Act to engage in certain remedial action in northwest Pennsylvania growing out of some old operations in that area.

While our detail comments on this damage have been filed with EPA under separate cover, suffice it to say that the practices which gave rise to this action are not indicative of current day practices and that the case demonstrates the scope and diversity of the legal authority which EPA and the Coast Guard believe they have under the Clean Water Act to address such cases.

5. Abandoned Wells.

Without citing any particular damage cases, EPA has concluded that there are many older wells in Pennsylvania which were drilled prior to the time that a bond was required to assure plugging upon abandonment. As the discussion correctly notes however bonds are now required. This conclusion identifies no problem which could be addressed by new regulations under Subtitle C of RCRA that has not already been addressed under state regulatory authority.

C. Zone 5 Conclusions.

Of the major issues identified for Zone 5 only three are related to Ohio.

1. Illegal Dumping of Waste in Ohio.

In support of this conclusion EPA relies upon damage cases OH01, OH07 and OH12. In addition even though EPA recognizes that Ohio has been aggressive in insisting on compliance from operators, EPA states its belief that illegal disposal practices are expected to continue.

With respect to case OH01, EPA is incorrect in determining that this case relates to Ohio at all. The case grows out of an operation in West Virginia where the company was cited with criminal charges.

With respect to cases OH07 and OH12 both statutes and regulations were violated by discharges which entered a surface stream. In addition to having violated a state regulations,

discharges to surface streams without a permit would be in violation of the federal Clean Water Act.

The conclusion reached by EPA in this context presents a curious "damned if you do and damned if you don't" dichotomy. If a state does not have a vigorous enforcement program it is criticized by EPA for failure to properly enforce its own rules. On the other hand if a state like Ohio has been aggressive in holding operators to the strict accountability for compliance with environmental programs the criticism is that "illegal" discharges are occurring. As with any regulatory program (including those directly administered by EPA) there will always be situations involving noncompliance with regulatory requirements. The question is not whether there have been or will be violations of regulatory requirements. Rather, the question is whether there is sufficient legal authority and resources to pursue those violations when they occur. The cases with respect to Ohio illustrate convincingly that there is adequate authority and resources to pursue noncompliance.

2. <u>Contamination of Ground Water from Injection and Annular Disposal.</u>

In support of this conclusion EPA cites the damage case <u>OH38</u> and its general understanding that annular disposal is not allowed in other states because of the potential for ground water contamination due to the corrosion of casings resulting from high chloride content.

First with respect to damage case <u>OH38</u> we should point out that the water well involved in that case showed contamination levels which predated the commencement of annular disposal.

Where is the evidence? This is not true & in fact Scott Kell stated when we met at his office that annular disposal was the reason for contamination.

In addition there was also evidence of the fact that the casing used in that situation may have been bad initially. More significantly however the state of Ohio has since adopted comprehensive regulations related to annular disposal which, among other things, provides that annular disposal systems must be maintained air tight (to eliminate corrosion) and be gravity fed. Moreover annular disposal is not permitted in Ohio unless conducted in accordance with agency regulations and with the agency's expressed approval.

Secondly, in addition to Ohio, the states of Kansas and Louisiana allow annular disposal. As was reported by Elmer E. Templeton & Associates in a report dated January 1980 entitled "Environmentally Acceptable Disposal of Salt Brines Produced with Oil and Gas, a report for the Ohio Water Development Authority". It was recommended that air tight systems be used to reduce dissolved oxygen contributing to corrosion.

recommended not required X Law

3. Contamination of Ground Water from Reserve Pits.

In support of this conclusion EPA relies on damage case OH49 and the general observation that Ohio does not have a statewide rule that requires liners in reserve pits.

OH49 is a case arising in the Lake Plains region of Ohio in 1983. At that time the discharge which contaminated a water well was a specific violation of state statutory and regulatory requirements for which enforcement action was taken. Since that time drilling pits in the Lake Plains region have been required by the state agency to use synthetic liners or steel pits. In addition, with the passage of S.B. 501, brine disposal

pits were prohibited from and after July 1, 1986. Thus the state has adequately addressed the concerns raised by damage case OH49.

CHAPTER IV - HUMAN HEALTH AND ENVIRONMENTAL HEALTH RISK ASSESSMENT.

With respect to this analysis we restate the objection contained in our comments filed on EPA's interim report on methodology on January 15, 1987. We do not believe that risk assessment analysis can be appropriately considered in connection with the study requirements mandated by RCRA §8002(m).

Moreover the process outlined in this chapter is little more than the compounding of various hypothetical situations with respect to which there is virtually no opportunity for validation of the results.

CHAPTER V - COSTS OF BASE LINE AND ALTERNATIVE WASTE MANAGEMENT PRACTICES.

The purpose of Chapter 5 was to provide estimates of the costs of baseline and alternative waste management practices for the oil and gas industry. Based on this study, EPA plans to assess the impact of alternative waste management practices on this industry. Many of the findings discussed in Chapter 5 do not provide an accurate representation of the baseline and alternative waste management practices available to the Appalachian Basin oil and gas industry or the costs associated with these management practices. In actuality, the current or "baseline" costs in the Appalachian Basin industry are significantly lower than is reflected by Chapter 5. This is an

important deficiency in the Interim Report because the incremental costs associated with additional regulations is likely to be much greater than indicated in Chapter 5 and subsequent studies. This issue and several others will be addressed on the comments which follow.

1. Real vs. Nominal Cash Flow.

The Interim Report states that the cost impact of potential regulations should be assessed using "real" (constant) dollars rather than nominal (current) dollars. The use of "real" cash flow is an attempt to remove the impact of inflation in making decisions. However, management decisions are not based upon a "real" hurdle rate of 8 percent, they are based upon a nominal hurdle rate of 16 percent.

EPA's use of an 8 percent hurdle rate would distort the actual return of a project by more than one percentage point. The overstatement of the return infers that a new well could absorb more regulatory costs ($1,200/year operating cost or $6,000 of drilling cost) than the project really could before becoming uneconomical to drill.

The reason for the distortion from using "real" cash flows is that tax writeoffs (depreciation of project's investment for tax purposes) are not inflation adjusted. In actuality, investments made in today's dollars will be written off against future inflated taxable income. Therefore, the "real" write offs would not offset as much income. Taxes would be disproportionately higher using "real" cash flows.

2. Return on Capital vs. Return of Capital.

On page 4, EPA defines the cost per barrel of disposed waste as follows:

$$\text{Cost per Barrel of disposed waste} = \frac{\text{Annual Oper. Costs} + \text{Annualized Capital Cost}}{\text{Barrels of waste disposed per year}}$$

All capital costs were annualized by EPA using an 8% discount rate. This leaves some uncertainty as to how the annualization was performed. There are at least two different ways that the annualization could be calculated, the first of which distorts any conclusions:

a) Annualized capital cost = (total capital cost) (0.08). This methodology incorporates an opportunity cost of capital into the Cost Per Barrel calculations and thus enables one to capture an 8% return on the capital invested in the project. In other words, this methodology recognizes the interest cost of borrowing the capital funds and adds it to the annual operating costs to be recovered. The problem with this methodology is that there is no provision made for the repayment of the borrowed capital or the replacement of the disposal facility at the end of its useful life. If EPA's contractors assume methodology A, then the implication would be that a project could absorb more waste disposal costs before it would become uneconomical to operate.

b) The second methodology would annualize the capital cost as that annual payment which over the life of the disposal site pays for both carrying cost on (return <u>on</u>) and replacement of (return <u>of</u>) the investments involved. In other words this would be analagous to a mortgage payment problem. For example, $500,000 capital spent in a site with a life of ten years, at 8% cost of capital, requires $74,515 per year in payments. This compares to only $40,000 (500,000 x .08) calculated under the previous method. Another factor complicating matters is that the interest portion of the $74,515 payment is deductible for tax purposes whereas the principal portion is not.

Incorporating the tax sheltering effects of depreciation can further complicate matters. The answer to these

complications is to iteratively solve for that dollar revenue per barrel that yields 8% on discounted cash flow basis after all operating costs, depreciation write offs, and income taxes. The Interim Report does not make it apparent which, if any, of the above methods were utilized.

3. Classification Based on Chloride.

A chloride limit of 500 ppm is shown on page 7 in Table 3-1 for determining if a produced water should be included in level 1, 2 or 3 of the intermediate scenario. Level 1 allows current practices, while level 2 requires injection into a Class II disposal well. This is not consistent with current EPA effluent guidelines where brine discharges from stripper oil wells are allowed regardless of chloride content, provided that the brine is diluted sufficiently with the receiving stream to insure that water quality standards are not exceeded. This assumption is also not consistent with current land application practices where it has been recognized that higher chloride concentrations can be successfully land applied.

4. Pit Costs.

Cost components of pit construction and closing not mentioned in Table 4-1 on page 12 include survey and design; reclamation plan and permit; drafting and typing for permit application; pit fluid analysis, treatment and discharge. Despite the apparent neglect of these components, the average cost of constructing and closing a .25 acre unlined pit was $26,500, which is significantly higher than actual costs currently experienced by the industry in the Appalachian Basin.

5. Lined Pit Disposal Costs.

The cost per barrel for disposing of wastes in lined pits in the Appalachian Basin is listed in Table 4-7, pages 18 and 21, as ranging from \$0.98/Bbl. to \$6.78/Bbl. However, since precipitation exceeds evaporation in the Appalachian Basin, disposal of fluid wastes in evaporation pits is not possible. Therefore, the costs calculated for this alternative in the Appalachian Basin should not be included in Table 4-7.

6. Conversion of Class II Wells.

The assumption was made on page 28 that no new wells would be drilled for Class II injection, instead, existing producing wells would be converted to injection as necessary. There are at least two reasons why this assumption is incorrect.

First, in low permeability reservoirs, where initial production was ≤10 barrels of fluid per day, it is unreasonable to assume that injection into a well would be sufficient to dispose of water from several producing wells. Therefore, either several wells would have to be converted or a new well drilled and completed in a different formation, if one capable of sufficient injectivity is available in the area.

Second, in several regions of the Appalachian Basin, all of the wells producing in a field were drilled prior to the existence of regulations for the oil and gas industry. Therefore, these wells do not have surface casing and extensive (perhaps cost prohibitive) work would be required to enable these wells to meet Class II injection regulations.

7. <u>Class II Well Costs</u>.

The following factors should be considered in Tables 6-1, 6-3, page 30, and Appendix B in determining the costs of Class II injection well and facilities in the Appalachian Basin:

1. If a well currently producing is converted to waste disposal, the revenues lost (i.e. projected production revenues from this well) should be considered as a cost for this conversion.

2. The costs listed in Appendix B for converting a producing well to Class II injection appear generally high. More specifically, completion rig, stimulation, logging and tubing expense are excessively high based upon Appalachian Basin experience.

3. Many components of the capital costs for a Class II injection facility are too high, resulting in an estimated cost that could be three times greater than the actual costs experienced by industry, as shown in Exhibit 1. In particular, the valves, tankage, filters, fittings, etc. and profit and overhead appear excessively high.

The operating costs of a Class II injection facility are documented in Appendix C of Chapter 5. Again, the operating costs listed for the Appalachian Basin appear high. Electric costs of $0.11/kwh are actually closer to $0.05/kwh. Also, the replacement of 5,324 filter elements per year (about 15 per day) would suggest the need for a change in the filter system design, especially if the original installation cost of $40,000 as indicated in Appendix B.

- <u>Injection Capacity</u>

The assumption appearing in Table 6-4, page 36, that a disposal well in the Appalachian Basin will be capable of inject-

ing 5,000 BPD for 20 years is grossly in error. This resulted in an estimated disposal cost of $0.38/Bbl. as listed in Table 6-4. In reality, a good disposal well in the Appalachian Basin might begin injecting 500 BPD, but the rate of injection normally declines according to Darcy's Law (refer to one of many Petroleum Engineering textbooks available) as the water injected into the receiving formation is displaced further from the wellbore of the disposal well. The injection rates actually achieved in the Class II wells are recorded as a part of Underground Injection Control Regulations and are available to EPA. Exhibit 2 is an injection well history for a 2,100' Class II well injecting into a typical Appalachian Basin formation. The per barrel costs of the Class II disposal alternative is significantly increased if the injection rate is reduced from 5,000 BPD to the actual injection rate achieved in the Appalachian Basin.

Also, it should be noted that even if a disposal well were available in the Appalachian Basin that could inject 5,000 BPD, the transportation costs associated with gathering this volume of brine for disposal would probably be prohibitive. This high transportation cost would be anticipated since the average producing well in the Appalachian Basin makes a small volume of water (as documented in "An Analysis of the Economic Impact of New Hazardous Waste Regulations in the Oil and Gas Industry in the Appalachian Basin") and therefore a significant gathering radius would be required to accumulate 5,000 BPD of produced fluids.

9. Factors Contributing to Disposal Costs.

Higher disposal costs in a given area may be a function of low permeability and the resultant low injectivity of formations available for disposal, not just the lack of competition as suggested on page 34.

10. Drilling Fluid Analysis.

The typical drilling fluid analyses presented in Table 9-3, page 51 and Table 10-1, page 55, are not an accurate representation of Appalachian Basin drilling pit fluids, where most of the wells are drilled using air rotary techniques and the water accumulated in the pit is actually produced from formations encountered during the drilling process.

11. Transportation Costs.

The transportation costs calculated in this section and summarized in Table 12-1, pages 65 and 66, are not accurate. The time required for loading and unloading the fluids was not included in the cost calculations. Time was only allowed for a one-way trip for the hauling truck, where in reality the operator would have to pay round-trip transit time. Even in good weather, it would not be advisable to travel 30 MPH on the lease and county roads where most production facilities in the Appalachian Basin are located. A lower speed should be assumed. In wet weather, costs for a bulldozer to assist the hauling truck on lease roads and additional transit time for the hauling truck should be included in transportation cost calculations.

The transportation cost of $0.01/Bbl./mile documented in this section, is simply not realistic for the Appalachian Basin.

CHAPTER VI - ECONOMIC IMPACT OF ALTERNATIVE WASTE MANAGEMENT PRACTICES FOR THE ONSHORE OIL AND GAS INDUSTRY.

According to the introduction of Chapter 6, "The purpose of this report is to establish baseline economic cases that can be used to simulate the economic performance of representative projects both with and without the cost of additional waste management practices."

The following comments are offered to provide an accurate evaluation of the baseline economics of investments available to the Appalachian Basin oil and gas industry and to avoid understating the impact of any future regulations.

1. Hurdle Rate.

We strongly disagree with the conclusion of the Interim Report that the Cost of Capital is equivalent to the Hurdle Rate. Common industry practice is that the Hurdle Rate is derived from several factors, only one of which is Cost of Capital:

- Cost of Capital
- Overhead Coverage
- Unusual Risk Exposure
- Intangibles

Page G-18 (Table G-6) of Chapter 6 displays how EPA derived their Cost of Capital. Historical data were used to derive (a) risk-free rate, (b) corporate borrowing rate (debt), and (c) inflation rate. We submit that exclusive use of the past to derive a cost of capital to be used in the future is inappropriate. The understanding of past relationships is important but only current business conditions and projections of future conditions should be used in the derivation of cost of

capital for making decisions in regard to long-lived projects such as oil and gas drilling.

Project economics are usually prepared on an "incremental" basis. Incremental economics include only those expenditures to be made in the future for the drilling and completion of a well. However, all wells together must pay for fixed expenses such as regional seismic lines, administrative costs, geology, and engineering that are unrelated to specific prospects. Therefore, the hurdle rate should compensate for the lower expenditures used in incremental economics. On average, the hurdle rate is raised two to three percentage points above the cost of capital in the Appalachian Basin to compensate for overhead.

The third component of the Hurdle Rate is "additional risk exposure." This risk exposure is in addition to "average risk" that is included in the calculation of cost of capital. There are two types of additional risk to be considered: (a) risk for those projects in which a large amount of capital is at risk such as exploratory wells, and (b) liability risk where there is a hugh loss exposure if something goes wrong. An example of a liability risk would be risk of an environmental problem from an unusual accident such as a blowout, oil spill, or pipeline break. Additional risk exposure will add from one to seven percentage points above the cost of capital.

Finally, intangibles should also be considered in the derivation of the hurdle rate. Intangibles could be something as discreet as whether or not a company has any taxable income. Tax

losses which are carried forward may never be used in the current business environment as numerous companies go bankrupt.

A second intangible to be considered is other investment alternatives for the capital dollars being considered. Size of a company has no impact on this consideration. For large companies using internal funds, the decision as to how much capital to spend in exploration and production is made after consideration of the returns of other investment opportunities (internal or external) for the company. Small companies, whose dominant source of capital is external, must consider how their exploration and development projects will compare with other investment opportunities for their outside sources of capital. Management will set the hurdle rate high enough so that only those projects which have competitive potential returns (with other investment opportunities) will be drilled.

The final intangible to be considered is the management strategy for long-term growth in assets value. In a public company, the Board of Directors will set the hurdle rate above the calculated cost of capital in order to enhance shareholder return. Their intent is to set the rate high enough so that only the better opportunities are chosen. In this way, profitability, assets, and ultimately the company's stock price will increase to meet long-term growth goals. The hurdle rate is set high enough in an attempt to make the company better than average.

Private companies set the hurdle rate for the same reasons. Management in private companies are concerned with increasing the value of their assets over time just like public

companies. In the case of private companies, market value is not measured by stock price.

On average, the intangible considerations will add two to three percentage points to the cost of capital in the current business environment.

We recommend a 16 percent hurdle rate for the Appalachian area for average projects instead of the 13 percent developed by EPA. As illustrated, riskier projects will require a higher hurdle of 20 percent. A 13 percent rate would create a large distortion for assession the impact of potential hazardous waste regulations. If a 13 percent hurdle rate were to be used, then EPA could state that the average project could absorb a greater amount of costs from new regulations before the return for the average project would fall below the hurdle rate. Any decision to invest in a project (e.g., enhanced recovery facilities) would be grossly distorted in a similar manner. The impact upon Appalachian operators from this potential understatement of the sensitivity of the average well to regulatory costs would be devastating. Our comments filed on February 10, 1987, demonstrated that even two hundred dollars per year of increased operating expense would shut-in nearly 19% of all Appalachian Basin wells. A lowering of the hurdle rate by three percentage points (to 13 percent) would imply that the average could absorb $3,000 per year in operating expense or $15,000 in additional drilling cost. Obviously, this implication is incorrect.

2. Sequence Logic.

The sequence logic used in the baseline cases on page 2-4 ignores waterflood and E.O.R. projects, where production response may not be achieved for 2 or more years after the initial investment is made. This fact significantly reduces the economic rate of return generated by those projects. Over 40% of the oil produced in the United States is from waterflood and E.O.R. projects, so they should not be excluded from EPA's study.

Also, in many cases it is several months or even years after initial geophysical work that an exploratory well is drilled. Then depending on company budget constraints and the length of time required to properly evaluate a successful exploratory well, it may be several additional months (or even years) before development drilling begins.

3. Cost Logic.

The operating costs documented in Appendix F, Page F-2, of $4,100/year is not representative of major companies in the Appalachian Basin, especially since overhead costs were not included in this annual cost. Up to an additional 25% could be added to this cost if overhead is included.

4. Need For Gas Well Model.

Since 53% of the successful wells (according to Table 3-4 of Chapter 6) drilled in the Appalachian Basin are gas wells and a significant portion of the industry is involved primarily in the production of natural gas, a study of the economic impact of alternative regulations would not be complete without considering gas wells.

5. <u>Well Costs</u>

The cost listed in Table 3-2 for drilling a typical Zone 2 well appears to be excessively below the drilling and completion costs actually incurred by the oil and gas industry in the Appalachian Basin. In order to calculate accurate baseline economics, the drilling costs employed must be a close approximation of actual costs. Therefore, additional research should be completed with regard to the references noted for Table 3-2 to determine if the costs listed are dry hole costs, or do they include costs for completion work and equipment. Dry hole cost is a term commonly used in the industry to indicate the cost of reaching total depth in a well and evaluating it's production potential prior to spending the significant additional costs required (such as production casing, formation stimulation and production equipment) to prepare a well for production. Exhibit 3 is a cost estimate for a 2,000 feet oil producer drilled in 1986. The estimated cost was $98,000.

6. <u>Wellhead Prices and Taxation</u>.

The baseline economic study documented in Chapter 6 is not accurate since inconsistent parameters were used on pages 3-9 and 3-12. For instance, a 1985 oil price (over $25.00/BO) was used but windfall profit taxes were excluded from this study. Also, while more favorable 1985 wellhead prices were applied, the current corporate tax rate (34%) was used rather than actual 1985 tax rate (48%). The combination of the parameters employed in EPA's baseline study will result in more favorable economics than actually generated by industry projects.

7. Internal Rate of Return.

Using the parameters outlined in Chapter 5, EPA performed cash flow analyses on baseline projects. Table 3-2 lists an internal rate of return of 10.3% for majors and 10.5% for independents. For reasons previously discussed in these comments, the validity of these cash flow analyses is questionable. Also, when considering overhead costs, risk factors, other investment opportunities, and additional intangible factors, an IRR of 10.5% may not be sufficient to justify an investment in the subject project.

CHAPTER VII - SUMMARY OF STATE AND FEDERAL REGULATIONS.

In our comments filed with EPA on January 15, 1987, a detailed review was provided of state regulatory programs in all seven Appalachian states. Exhibit 4 to these comments focuses on the Appalachian states which were emphasized by EPA in its Interim Report - Ohio and West Virginia. The exhibit reviews the regulatory requirements of these two states within specifically identified categories.

CONCLUSION

The Interim Report issued on April 30, 1987, is seriously flawed for the reasons described in these comments and undoubtedly others. These issues should be addressed by EPA prior to preparing its draft Report to Congress.

Respectfully submitted this 13th day June, 1987.

INDEPENDENT OIL AND GAS ASSOCIATION OF NEW YORK
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Exhibit 1

FORM 25 116

AUTHORIZATION FOR EXPENDITURE
PRODUCTION EQUIPMENT AND/OR OTHER COSTS

DATE: July 16, 1982 | PAGE: 1 of 1

Co.: 0 1 | Dept: 1 | Play No.: 1 4 3 1 | AFE No: 7 1 2 0 4 8 4 | AFE Title or Location Name (29): TARIFF WF EXP PLANT & LINE

COMPANY: Pennzoil Exploration & Production | DIVISION: Eastern | DISTRICT: Parkersburg

WELL NAME AND NO: Tariff Water Plant & Lines | FIELD OR AREA: Tariff #8000 | UNDEVELOPED LEASE NO.:

OPERATOR: | COUNTY OR PARISH: Roane | STATE: West Virginia

PROJECT DESCRIPTION: Install water injection facilities | LEASE NAME AND NO.: Tariff Unit #10-09917

PROPOSED FORMATION:

Single ☐ Triple / Dual / Land ☐ Bay / Marsh ☐ Gulf | ☐ Oil ☐ Gas | DATE TO START | ☐ Expl ☒ Dev | DATE TO COMPLETE | ☒ New ☐ Workover | DAYS TO DRILL | Deepen ☐ Yes ☒ No | PROPOSED DEPTH

Gross: 1 0 0 0 0 0 | Net: 8 7 5 0 0 0 | Budget Code: 7 1 0 2 | Ls/Assoc Prop No.: 2 0 0 0 1 1 5 | Assoc. AFE No.: | Joint Venture: ☒ No ☐ Yes | Operator: ☒ 2-Co. ☐ 3-Outsd. | State Code: 4 7

County Code: 0 8 7 | Civil Dist: 0 3 4 0 | Regulated: ☐ No ☐ Yes | Report to Code: | Costing Location Mstg: | Environmental Cost: % Air: 0 0 0 | % Water: 2 0 0 | % Land - Other: 2 0 0 | % Safety and Health: 2 0 0

JUSTIFICATION

DETAIL OF PRODUCTION EQUIPMENT AND OTHER COSTS

Account Maj.	Account Sub	DESCRIPTION	QUANTITY	AMOUNT 100%
146	456	Supply - Extend existing WSW line to new plant site (5-1/2" cond. "B" csg. @ $7.70/ft w/installation)	1,300'	10,000
		Pump Equipment		
146	125	24' x 40' x 8' Building, including set up	1	34,500
146	452	50 HP motor for injection pumps	2	3,600
146	453	Murphy Pannels	2	2,800
146	460	Injection pumps, 323 used	2	9,600
		Filter Equipment		
146	125	24' x 32' x 10' Building, including set up, installation	1	34,100
146	460	Backwash pump w/motor	1	1,500
146	469	6' x 5' Squibb coal filter	4	16,000
146	453	3-Phaser Power to plant site	1 Lot	79,800
146	457	Tanks - 210 Bbl w/walkways and stairs	3	8,000
146	501	Company Labor	1 Lot	15,000
146	505	Benefits	1 Lot	5,000
146	545	Dozer & Trucking	1 Lot	12,000
146	598	Miscellaneous	1 Lot	16,000
146	456	Water Injection Lines	1 Lot	79,000
		TOTAL		326,900

NOTE: Due to time constraints, a survey of Class II injection facility costs in the Appalachian Basin was not possible. This exhibit therefore represents the 1982 costs of one operator rather than an industry average.

SUMMARY OF ESTIMATED COST

PROPERTY ADDITIONS

REMOVAL COST

SALVAGE

TOTAL COST: 100.00000 %

CO. OWNERSHIP: 100.00000 % | COMPANY COST: 100.00000 % | 326,900

APPROVAL | DATE | APPROVAL | DATE | AUTHORIZATION | DATE

JOINT INTEREST APPROVAL

COMPANY NAME: | %

APPROVAL: | DATE

NO. 340 L310 DIETZGEN GRAPH PAPER
SEMI-LOGARITHMIC
3 CYCLES X 12 DIVISIONS PER INCH

EUGENE DIETZGEN CO.
MADE IN U. S. A.

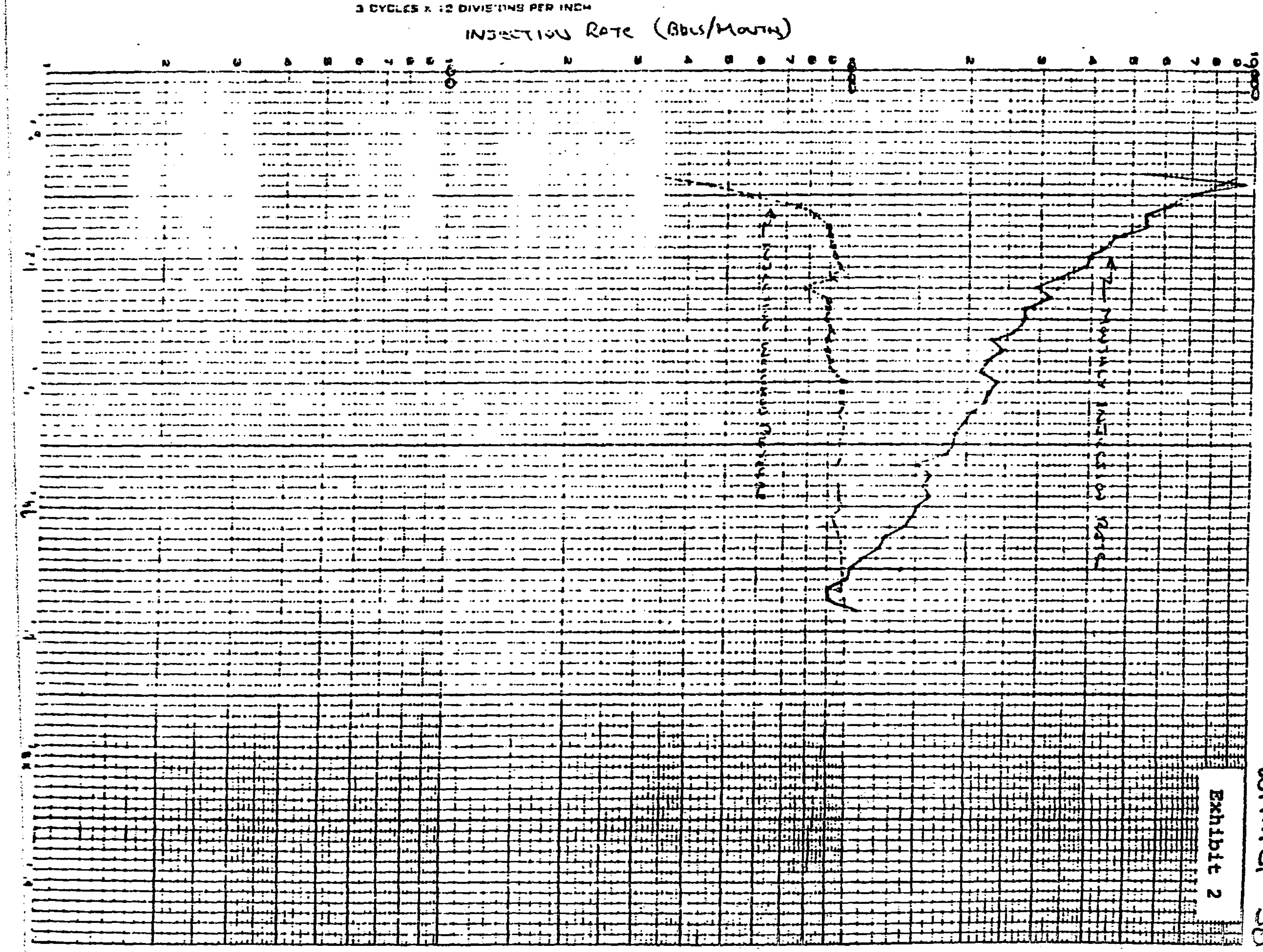

Exhibit 2

W.M.C. #38

Farm Name W. M. LOONEY

Year 1983 INJECTION DATA

Well No. 38

Year 1983

Month	Avg. Press.	Avg. Rate	Water	Cum. Water
January				
February				
March				
April				
May				
June				
July				
August				
September				
10-15-83 October	297	312	5300	5300
November	452	319	9556	14,856
December	567	217	6738	21,594
Total				

Year 1984

Month	Avg. Press.	Avg. Rate	Water	Cum. Water
January	756	203	6296	27,890
February	826	187	5429	33,319
March	890	175	5417	38,736
April	898	153	4579	43,315
May	917	142	4391	47,706
June	930	132	3947	51,653
July	956	124	3840	55,493
August	915	109	3386	58,879
September	788	97	2928	61,807
October	894	102	3159	64,966
November	895	92	2764	67,730
December	888	89	2770	70,500
Total				

Year 1985

Month	Avg. Press.	Avg. Rate	Water	Cum. Water
January	902	85	2631	73,131
February	890	82	2299	75,430
March	889	79	2444	77,874
April	904	74	2229	80,103
May	925	69	2145	82,248
June	983	79	2362	84,610
July	915	74	2279	86,889
August	973	71	2203	81,092
September	966	68	2034	91,126
October	982	64	1990	93,116
November	983	63	1882	94,998
December	975	60	1865	96,863
Total				

Year 1986

Month	Avg. Press.	Avg. Rate	Water	Cum. Water
January	975	57	1769	98,632
February	958	54	1513	100,145
March	950	53	1639	101,784
April	963	53	1581	103,365
May	965	53	1639	105,004
June	988	50	1511	106,515
July	938	48	1497	108,012
August	945	46	1439	109,451
September	975	42	1262	110,713
October	975	40	1230	111,943
November	985	38	1138	113,081
December	988	34	1039	114,120
Total				

Farm Name [illegible]

Year 1987 INJECTION DATA

Well No. 38

Month	Avg. Press.	Avg. Rate	Water	Cum. Water
January	995	32	1005	115,125
February	975	31	902.	116,027
March	975	31	916	116,943
April	1006	36	1080	118,023
May				
June				
July				
August				
September				
October				
November				
December				
Total				

Year

Month	Avg. Press.	Avg. Rate	Water	Cum. Water
January				
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				
Total				

Year

Month	Avg. Press.	Avg. Rate	Water	Cum. Water
January				
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				
Total				

Year

Month	Avg. Press.	Avg. Rate	Water	Cum. Water
January				
February				
March				
April				
May				
June				
July				
August				
September				
October				
November				
December				
Total				

AUTHORIZATION FOR EXPENDITURE
WELLS

Exhibit 3

Co.	Dept.	Play No.	AFE No.	AFE Title or Location Name (23)	Date	Page
0,1	1	1,2,0,1	7,0,2,0,8,0,2	T,A,R,I,F,F, ',8,6, E,X,P,A,N, 1,0,-,0,9,9,1	March 14, 1986	1 of 2

COMPANY	PEPCO
DIVISION	EASTERN
DISTRICT	PARKERSBURG
WELL NAME AND NO.	Tariff Unit No. 1 10-09917
FIELD OR AREA	Tariff #8000
UNDEVELOPED LEASE NO.	
OPERATOR	PEPCO
COUNTY OR PARISH	Roane
STATE	West Virginia
PROJECT DESCRIPTION	Drill one producing well.
LEASE NAME AND NO.	Tariff Unit No. 1 10-09917
PROPOSED FORMATION	Big Injun

☒ Single ☐ Triple ☐ Dual ☒ Land ☐ Bay ☐ Marsh ☐ Gulf ☒ Oil ☐ Gas ☐ Expl. ☒ Dev. ☒ New ☐ Workover Deepen ☐ Yes ☒ No

DATE TO START | DATE TO COMPLETE | DAYS TO DRILL | PROPOSED DEPTH

Gross	Net	Budget Code	Ls./Assoc. Prop. No.	Assoc. AFE No.	Joint Venture	Operator
1,.,0,0,0,0,0,0	.,8,7,5,0,0,0	7,1,0,6	1,0,0,9,9,1,7		☒ No ☐ Yes	☒ 2-Co. ☐ 3-Outsd.

County/Ph. Code	Civil Dist.	Required?	Report to Code	Costing Location Mktg	Environmental Cost % Air	% Water	% Land - Other	% Safety and Health
0,8,7	0,3,4,0	☐ No ☐ Yes	1,6,4,7,6,8,0,0,0		1,0,0	4,0,0	5,0,0	2,0,0

JUSTIFICATION

"SEE ATTACHED JUSTIFICATION"

INTANGIBLES			SUB	DRY HOLE	COMPLETION	TOTAL
CONTRACT DRILLING						
CONTRACT DAY WORK — DRILLING	2,000 ft. @ $ 850	/ft.	489	17,000		17,000
CORING AND DRILL STEM TEST	1/2 days @ $ 3,800	/day	490	1,900		1,900
LOGGING, SFT, AND PERFORATING	days @ $	/day	490			
OTHER	4 days @ $ 500	/day	490			
TOTAL CONTRACT DAY WORK			490	2,000		2,000
COMPANY PAYROLL			490	3,900		3,900
EMPLOYEE BENEFITS			501	5,000		5,000
TRANSPORTATION AND HAULING			505	1,667		1,667
ACCESS CANAL CONSTRUCTION			545	3,000		3,000
LOCATION, ROADS, PITS OR KEYWAY & Reclamation			476			
BITS, COREHEADS, ETC.			472	12,000		12,000
MUD MATERIALS			492			
CEMENT AND CEMENTING SERVICES			475	2,000		2,000
CENTRALIZERS, SHOES, SCRATCHERS AND NON-SALVABLE PACKERS			473	4,100		4,100
MUD LOGGING			491	1,200		1,200
FORMATION TESTING			474			
LOGGING AND SIDE WALL CORING			482			
PERFORATING			478	1,800		1,800
TOOL RENTAL INCLUDING SMALL DIAMETER DRILL PIPE			479	1,100		1,100
TESTING TUBULAR GOODS			488	250		250
INTERNAL COATING			484			
STIMULATION TREATMENT			485			
OTHER SPECIAL WELL SERVICES			480	3,600		3,600
MISCELLANEOUS COSTS AND CONTINGENCIES			494			
TOTAL INTANGIBLES			599	5,333		5,333
TANGIBLES						61,950

	ft.	in.	lb.	Gr.	@ $	SUB	DRY HOLE	COMPLETION	TOTAL
CASING	300	8-5/8	20	H-40	6.10/ft	440	1,830		1,830
	2000	4½"	9.5#	K-55	2.90/ft	440	5,800		5,800
						440			
TUBING	1950	2-3/8"	4.6#	K-55		440			
					1.60/ft	443	3,120		3,120
						443			
						443			
						444	800		800
						445			
						448			
						469	1,500		1,500

NOTE: Due to time constraints, a survey of drilling costs in the Appalachian Basin was not possible. Therefore, this exhibit represents a typical drilling cost of one company rather than an industry average.

	00.00000 %			13,050
	00.00000 %			75,000
OTHER COSTS - NET (Detail Attached)	100.00000 %			23,000
TOTAL COST	100.00000 %			
CO. OWNERSHIP 1.0000000 % — COMPANY COST	0.000000 %			98,000
				98,000

APPROVAL DATE | APPROVAL DATE | AUTHORIZATION DATE

JOINT INTEREST APPROVAL

COMPANY NAME

APPROVAL % DATE

AUTHORIZATION FOR EXPENDITURE
PRODUCTION EQUIPMENT AND/OR OTHER COSTS

DATE: March 14, 1986 | PAGE 2 OF 2

Dept.	Play No.		AFE No.		AFE Title or Location Name (25)
0 1 1	1 2 0 1		7 0 2 0 8 0 2		TARIFF '86 EXPAN 10-0991

COMPANY | DIVISION | DISTRICT

WELL NAME AND NO. | FIELD OR AREA | UNDEVELOPED LEASE NO.

OPERATOR | COUNTY OR PARISH | STATE

PROJECT DESCRIPTION | LEASE NAME AND NO.

PROPOSED FORMATION

☐ Single ☐ Triple ☐ Dual ☐ Land ☐ Bay ☐ Marsh ☐ Gulf | ☐ Oil ☐ Gas | DATE TO START | ☐ Expl. ☐ Dev. | DATE TO COMPLETE | ☐ New ☐ Workover | DAYS TO DRILL | Deepen ☐ Yes ☐ No | PROPOSED DEPTH

Gross | Net | Budget Code | Ls./Assoc. Prop. No. | Assoc. AFE No. | Joint Venture ☐ No ☐ Yes | Operator ☐ 2-Co. ☐ 3-Outsd.

County/Ph. Code | Civil Dist. | Conveyed ☐ Yes ☐ No | Report to Code | Costing Location Mktg | Environmental Cost: % Air | % Water | % Land - Other | % Safety and Health

JUSTIFICATION

DETAIL OF PRODUCTION EQUIPMENT AND OTHER COSTS

#	Account Maj	Account Sub	DESCRIPTION	QUANTITY	AMOUNT 100%
1	146	451	Pumping Unit base and pad		
1	146	455	5/8" sucker rods @ $0.55/ft.	1 Lot	4,500
1	146	454	Rod pump	1,950'	1,073
1	146	452	Electric motor and controller	1 Lot	475
1	146	453	Electric hook-up	1 Lot	626
1	146	453	Electric line @ $10.00/ft.	1 Lot	900
1	146	456	2" oil line @ $1.32/ft.	500'	5,000
1	146	510	2" oil line installed @ $2.00/ft.	1,500'	1,980
1	146	501	Company Labor	1,500'	3,000
1	146	505	Company benefits	1 Lot	2,500
1	[illegible]	[illegible]	[illegible] and Trucking	1 Lot	834
1	146	598	Misc.	1 Lot	1,500
				1 Lot	612
			TOTAL		23,000

SUMMARY OF ESTIMATED COST

1	PROPERTY ADDITIONS
3	REMOVAL COST
5	[illegible]

CO. OWNERSHIP 1 0 0 0 0 0 0 0 % | TOTAL COST 100.00000 % 23,000

APPROVAL DATE | APPROVAL DATE | COMPANY COST 1 0 0 0 0 0 0 0 0 % 23,000 | AUTHORIZATION DATE

JOINT INTEREST APPROVAL

COMPANY NAME:

APPROVAL | % | DATE

NOTICE: If the film image is less clear than this notice, it is due to the quality of the document being filmed

OGRA 019

1996

Exhibit 4

I. OHIO

A. Reserve Pit Design, Construction and Operation

1. Performance Standard

ORC 1509.22 (C)(3): Brine and other wastes associated with drilling, fracturing, etc. may be contained in pits, but the pits must be designed "to prevent the escape of brine."

2. Liners

OAC 1501:9-1-07: Well operations must be conducted "in a manner which will not contaminate or pollute the surface of the land, or water on the surface of the land, or water on the surface or in the subsurface."

3. Overtoppings

OAC 1501:9-1-07: Well operations must be conducted "in a manner which will not contaminate or pollute the surface of the land, or water on the surface or in the subsurface."

4. Commingling Provision

No such provision was identified in the regulations.

5. Permitting/Oversight

ORC 1509.22(C) gives the chief of the division of oil and gas the authority to regulate the storage and disposal of brine and other waste substances.

B. Reserve Pit Closure/Waste Removal

1. Deadline/General Standard

ORC 1509.072(A): "Within five months after . . . surface drilling of a well is commenced, the owner . . . shall, in accordance with his restoration plan filed [with the chief of the division of oil and gas], fill all the pits for containing brine, other waste substances resulting, obtained, or produced in connection with [the drilling operation] . . . and remove all concrete bases, drilling supplies, and drilling equipment. Within nine months after the date upon which the surface drilling of a well is commenced, the owner or his agent shall grade or terrace and plant, seed, or sod the area disturbed that is not required in production of the well."

2. Land Disposal/Application

OAC 1501:9-1-07: Well operations must be conducted "in a manner which will not contaminate or pollute the surface of the land.

3. Road Application

ORC 1509.226(A) provides that if a local government chooses to permit the surface application of brine to roads and similar surfaces within its jurisdiction, then such activity is permitted. Otherwise, it is prohibited. ORC 1509.226(B) establishes specific standards for road spreading.

4. Surface Water Discharge

ORC 6111.04: "No person shall cause pollution or place or cause to be placed any sewage, industrial waste, or other wastes in a location where they cause pollution of any waters of the state . . . except in such cases where the director of environmental protection has issued a . . . permit." This provision does not apply to wastes associated with oil and gas drilling that are disposed of in a well pursuant to a permit issued under Chapter 1509.

OAC 1501:9-1-07: Well operations must be conducted "in a manner which will not contaminate or pollute . . . water on the surface or in the subsurface."

5. Annular Injection

ORC 1509.22(C)(1) provides that "(b)rine shall only be disposed of by injection into an underground formation, including annular disposal if approved by rule of the chief [of the division of oil and gas], which injection shall be subject to division (D) of this section." Division D requires a permit for injection of brines or other waste substances unless a rule of the chief expressly authorizes permitless injections.

C. Produced Water Pit Design and Construction

1. Performance Standard

ORC 1509.22(C)(4): "Earthen impoundments constructed pursuant to the division's specifications may be used for the temporary storage of brine and other waste substances in association with a saltwater injection well, an enhanced recovery project, or a solution mining project."

ORC 1509.22(C)(5) states that brine may not be temporarily stored in pits or impoundments except as provided in ORC 1509.22(C)(3) and (C)(4).

ORC 1509.22(C)(6) forbids the use of a pit for the ultimate disposal of brine.

2. Liners

There is no explicit provision, but liners may be required to satisfy ORC 1509.22(C)(3).

3. Permitting/Oversight

ORC 1509.22(C) gives the chief of the division of oil and gas the authority to regulate the storage and disposal of brine and other waste substances.

D. Produced Water Surface Discharge Limits

1. Onshore

ORC 6111.04: "No person shall cause pollution or place or cause to be placed any sewage, industrial waste, or other wastes in a location where they cause pollution of any waters of the state . . . except in such cases where the director of environmental protection has issued a . . . permit." This provision does not apply to wastes associated with oil and gas production that are disposed of in a well pursuant to a permit issued under Chapter 1509.

OAC 1501:9-1-07: Well operations must be conducted "in a manner which will not contaminate or pollute . . . water on the surface or in the subsurface."

OAC 3745-33-02 requires an NPDES permit for pollutant discharge.

2. Coastal/Tidal

Not applicable.

3. Beneficial Use

ORC 1509.226(A) - A local government can permit the surface application of brine to its roads, etc. for the control of dust or ice. ORC 1509.226(B) establishes standards for such road spreading.

E. Produced Water Injection Well Construction

1. Casing

OAC 1501:9-3-05.(A)(1): "Surface casing shall be free of apparent defects and set at least fifty feet below the deepest underground source of water containing less than ten thousand mg/L total dissolved solids or less than five thousand mg/L chlorides, and sealed by circulating cement to the surface under the supervision of the division. In the event cement fails to circulate to the surface, the division may approve a remedial course of action."

2. MIT Pressure and Duration

OAC 1509:9-3-07(G): "Mechanical integrity shall be shown by one or more of the following methods:

(1) The casing, tubing, and packer shall be tested by pressurizing the annulus between the tubing and the casing outside the tubing to an amount equal to the maximum allowable injection pressure as determined in paragraph (D) of [OAC 1509:9-3-07] or to a pressure of three hundred pounds per square inch (psi), whichever is greater, for a duration of fifteen minutes with no more than five per cent decline in pressure unless otherwise approved by the division;

(2) Tracer surveys;

(3) Noise logs;

(4) Temperature surveys; or

(5) Any other logs or tests considered effective by the chief."

3. MIT Frequency

OAC 1501:9-3-07(G): If the annulus cannot be monitored during injection of fluids, then the well owner must prove mechanical integrity once every five years.

4. <u>Area of Review</u>

OAC 1501:9-3-06(B): The area of review for wells in which injection exceeds 200 barrels per day per year shall have a radius of one-half mile. The area of review for wells in which the maximum injection is 200 barrels per day per year shall have a radius of one-quarter mile.

5. <u>Annular Disposal</u>

OAC 1501:9-3-11: Disposal of salt water into any annular space is prohibited, except where the practice has been approved by the division of oil and gas and is performed in accordance with the standards imposed by this rule.

OAC 1501:9-3-11(C) discusses volume limitations.

F. Produced Water Injection Well Abandonment

1. Plugging Deadline

OAC 1501:9-11-05(C): Abandoned production or injection well plugging operations must begin without delay after production or injection operations have ended. The chief or his authorized representative may grant exceptions.

2. Plugging Specifications

Specifications are given in great detail in OAC 1501:9-11-07 to -09.

3. Plugging Oversight

OAC 1501:9-11-12(A): "Within thirty days after completion of the plugging operation, a plugging report on a form provided by the division and signed by the inspector present at the plugging operation, shall be filed with the division. A cementing report made by the party cementing the well or a copy of the prepared clay purchase record shall be attached to the plugging report. If plugging operations were not witnessed by an inspector a plugging report . . . signed by the owner or his agent shall be submitted to the division within thirty days after completion of the plugging operation."

II. WEST VIRGINIA

A. Reserve Pit Design, Construction and Operation

1. Performance Standard

Series 1, Section 16.4.1, Dept. of Energy, Div. of Oil and Gas Rules: Pits must be designed "and maintained so as to prevent seepage, leakage or overflows and to maintain [their] integrity."

Water Pollution Control Permit No. WV 0073343(G)(1): "The discharge of treated or untreated pit wastewater or sludge, caused by any reason such as . . .leaking or overflowing or an unstable or breached pit, into the water of the State is prohibited."

Water Pollution Control Permit No. WV 0073343(G)(10) provides specifications for pit construction.

2. Liners

Series 1, Section 16.4.4, Dept. of Energy, Div. of Oil and Gas Rules: "If existing soil is not suitable to prevent seepage or leakage, other materials which are impervious shall be used as a liner for a pit. Any such liner shall be installed in such a manner as to protect the structural integrity of both pit and liner."

Water Pollution Control Permit No. WV 0073343(G)(10)(d) contains identical requirements to Series 1, Section 16.4.4, Department of Energy, Division of Oil and Gas Rules.

3. Overtopping

Series 1, Section 16.4.3, Dept. of Energy, Div. of Oil and Gas Rules: If an operator cannot maintain adequate freeboard to prevent pit overflow, another pit must be built conforming to the pit construction specifications in Section 16.4.

Water Pollution Control Permit No. WV 0073343(G)(10)(c) contains requirements identical to Series 1, Section 16.4.3, Department of Energy, Division of Oil and Gas Rules.

4. Commingling Provision

Water Pollution Control Permit No. WV 0073343(G)(7): The following materials may not be dumped into a pit: production brine (produced water); unused frac fluid or acid; compressor oil, trash, rubbish and other refuse, diesel, kerosene, halogenated phenol and drilling additives prepared in diesel or kerosene; and any waste fluids after initial treatment of the pit waste.

5. Permitting/Oversight

Series 1, Section 16.1.1, Dept. of Energy, Div. of Oil and Gas Rules: "A proposed reclamation method for construction of . . . pits . . . shall be submitted on Form WW-9 with the application for any permit required by W.Va. Code §22B-1-6. . . . Such proposed reclamation methods shall be approved by the Director or his designate, prior to the issuance of the permit, all reclamation shall be done under the supervision of the Director."

B. Reserve Pit Closure/Waste Removal

1. Deadline/General Standard

W.Va. Code §22B-1-30(a) - Pits not needed for production purposes or not required by law or rule must be filled within six months after the drilling process has been completed. All concrete bases, drilling supplies, and drilling equipment must also be removed at this time.

W. Va. Code §22B-1-6(d): "An erosion and sediment control plan shall accompany each application for a well work permit except for a well work permit to plug or replug any well."

2. Land Disposal/Application

Water Pollution Control Permit No. WV 0073343 contains various requirements for land application

3. Surface Water Discharge

The Water Pollution Control Act, W.Va. Code §20-5A-5 prohibits point source discharges to State waters without a permit. State waters include both surface and groundwater.

Series 1, Section 7.2, Dept. of Energy, Div. of Oil and Gas Rules: "No discharge of salt water, brackish water, or other water unfit for domestic livestock or other general use shall be made into the waters of the State."

W. Va. Code §22B-1-7 requires water pollution control permits, grants the director of the division of oil and gas, department of energy enforcement authority, and provides penalties for violations of this section.

C. Produced Water Pit Design and Construction

1. Performance Standard

Series 1, Section 16.4.1, Dept. of Energy, Div. of Oil and Gas Rules: "Any pit shall be constructed and maintained so as to prevent seepage, leakage or overflows and to maintain its integrity.

2. Liners

Series 1, Section 16.4.4, Dept. of Energy, Div. of Oil and Gas Rules: Liners are needed if the existing soil does not prevent seepage or leakage.

3. Permitting/Oversight

Series 1, Section 16.1.1, Dept. of Energy, Div. of Oil and Gas Rules: "A proposed reclamation method for construction of . . . pits . . . shall be submitted on Form WW-9 with the application for any permit required by W.Va. Code §22B-1-6. Such proposed reclamation methods shall be approved by the Director or his designate, prior to the issuance of the permit, all reclamation shall be done under the supervision of the Director."

D. Produced Water Surface Discharge Limits

1. Onshore

The Water Pollution Control Act, W.Va. Code §20-5A-5 prohibits point source discharges to State waters without a permit.

Series 1, Section 7.2, Rules of Div. of Oil and Gas: "No discharge of salt water, brackish water, or other water unfit for domestic livestock or other general use shall be made into the waters of the State."

Series 4, Section 3.1, Rules of the Div. of Oil and Gas: "No person shall discharge pollutants . . . into surface waters of the State except as authorized pursuant to State NPDES permit, general permit or combined well work permit."

2. Coastal/Tidal

Not applicable.

3. Beneficial Use

Road spreading of brines is not prohibited and is currently being studied.

4. Permitting/Oversight

Series 4, Section 3.1, Dept. of Energy, Div. of Oil and Gas Rules: A State NPDES permit is required for discharge into State waters.

E. Produced Water Injection Well Construction

1. Casing

Series, Section 7.1.1, Department of Energy, Division of Oil and Gas Rules: "Injection of water, other liquids, or wastes shall be accomplished through a tubing and packer arrangement with the packer set immediately above the injection zone, and the annulus between the tubing and casing shall be monitored by pressure sensitive devices or through production casing adequately seated and cemented that will allow monitoring of the annulus between the injection casing and last intermediate casing string or coal-fresh water casing string, as the case may be.

2. MIT Pressure and Duration

Series 1, Section 7.3, Department of Energy, Division of Oil and Gas Rules discusses requirements for mechanical integrity testing.

3. MIT Frequency

Series 1, Section 7.7.2, Department of Energy, Division of Oil and Gas Rules: "The mechanical integrity of a liquid injection or waste disposal well must be demonstrated to the approval of the Director again within five years from the last test date order for injection to continue."

4. Abandoned Wells

W.Va. Code §22B-1-23 - "Prior to . . . the abandonment of any well, the well operator shall either (a) notify . . . the director and the coal operator operating coal seams, the coal seam owner of record or lessee of record . . . and the coal operators . . . of its intention to plug and abandon any such well."

Series 1, Section 13, Department of Energy, Division of Oil and Gas Rules discusses requirements for the plugging, abandonment, and reclamation of wells.

F. Produced Water Injection Well Abandonment

1. Plugging Deadline

W.Va. Code §22B-1-19 - "Any well which is completed as a dry hole or which is not in use for a period of twelve consecutive months shall be presumed to have been abandoned and shall promptly be plugged by the operator . . . unless the operator furnishes satisfactory proof to the director that there is a bona fide future use for such a well."

2. Plugging Specifications

Very detailed specifications are spelled out in W.Va. Code §22B-1-24.

Series 1, Section 14, Department of Energy, Division of Oil and Gas Rules discusses materials used in well plugging and application for well plugging.

3. Plugging Oversight

W.Va. Code §22B-1-23: Before plugging operations and abandonment commence, the director must be given a bond.

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FIRST NATIONAL BUILDING

February 23, 1987

FEDERAL EXPRESS

Mr. Dan Derkics
Office of Solid Waste
United States Environmental Protection Agency
401 M Street, S.W.
Washington, D.C. 20460

Re: Oil and Gas Waste RCRA §8002(m) Study.

Dear Mr. Derkics:

Enclosed for your consideration are 3 copies of "An Analysis of Damage Assessment Cases Reviewed by the United States Environmental Protection Agency for the States of West Virginia and Ohio in Connection with its Review of Oil and Gas Waste Pursuant to RCRA §8002" which is submitted on behalf of the

Independent Oil and Gas Association of New York
Independent Oil and Gas Association of West Virginia
Kentucky Oil and Gas Association
Ohio Oil and Gas Association
Pennsylvania Natural Gas Associates
Pennsylvania Oil and Gas Association
Tennessee Oil and Gas Association
Virginia Oil and Gas Association
West Virginia Oil and Natural Gas Association

Should you have any questions regarding the enclosed material, please contact me.

Very truly yours,

David M. Flannery

David M. Flannery

DMF:jsp
Enclosures
cc: Mr. Robert Hall (WH-565E)
Ms. Susan deNagy (WH-552)

AN ANALYSIS OF DAMAGE ASSESSMENT CASES REVIEWED BY THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY FOR THE STATES OF WEST VIRGINIA AND OHIO IN CONNECTION WITH ITS REVIEW OF OIL AND GAS WASTE PURSUANT TO RCRA §8002.

ON BEHALF OF THE

INDEPENDENT OIL AND GAS ASSOCIATION OF NEW YORK
INDEPENDENT OIL AND GAS ASSOCIATION OF WEST VIRGINIA
KENTUCKY OIL AND GAS ASSOCIATION
OHIO OIL AND GAS ASSOCIATION
PENNSYLVANIA NATURAL GAS ASSOCIATES
PENNSYLVANIA OIL AND GAS ASSOCIATION
TENNESSEE OIL AND GAS ASSOCIATION
VIRGINIA OIL AND GAS ASSOCIATION
and the
WEST VIRGINIA OIL AND NATURAL GAS ASSOCIATION

Submitted By:

Robinson & McElwee

David M. Flannery
Robert E. Lannan

Post Office Box 1791
600 United Center
Charleston, West Virginia 25301
304/344-5800

February 23, 1987

In connection with its study of oil and gas waste pursuant to RCRA §8002 for purposes of determining whether such waste should be regulated as hazardous waste, EPA, through its contractor, Versar, has undertaken an examination of the complaint files of various states to identify documented cases of environmental harm resulting from surface runoff and leachate from the exploration, development and production of oil and gas.

As it relates to the Appalachian Basin, Versar has examined damage cases for the States of West Virginia and Ohio. These trade organizations have obtained from these states the information that was provided to Versar. This paper will review those complaints and offer observations bearing upon the relevance of those complaints to the scope of EPA's study and commenting upon the adequacy of state regulatory programs to respond to those complaints.

No comment will be offered at this time on the adequacy of the documentation of these complaints.

I. WEST VIRGINIA

We have been advised by the West Virginia Department of Natural Resources that Versar has been provided with copies of documents related to some 44 complaints which have been registered with that agency from 1970 to date. Attached and identified collectively as Exhibit A is a summary of each of those 44 complaints. In each case, we have identified the environmental damage which is apparent on the face of that complaint and provided a description of the nature of the operation which is

alleged to have caused the environmental damage. In each case, we have also provided an assessment of the enforcement action, if any, that was taken in response to the complaint, as well as an identification of existing regulatory requirements applicable to each case.

Our review of this data indicates that five of the cases should be disregarded. The complaints dated April 25, 1975 and April 4, 1976 are not related to surface runoff or leachate. The complaints dated June 23, 1977 and June 25, 1984, are not associated with the exploration, development or production of oil and gas. The complaint of March 16, 1981 appears to indicate no environmental harm.

In 22 of the remaining 39 cases, criminal enforcement actions were taken by state regulatory agencies. In addition, there were 8 cases in which the person responsible for the discharge was assessed a monetary penalty equal to the replacement value of any fish that may have been killed by the discharge. In 4 cases the agency ordered remedial action. There are an additional 12 cases in which the nature of any enforcement action that might have been taken is either unknown or nonexistent.

Most significantly, however, our review of these cases has identified clear statutory or regulatory authority already in existence that can be used to prevent or minimize the environmental harm. West Virginia has implemented a general permit to regulate drilling pits and drilling fluid discharges since 1985. A general permit regarding produced fluid is currently being

developed. It is apparent, therefore, that no additional regulatory authority need be established pursuant to RCRA Subtitle C, or otherwise, to provide regulatory agencies with additional tools to address these situations.

II. OHIO.

We have been advised by the Chio Department of Natural Resources that Versar has been provided with copies of documents related to 4 cases. Attached and identified collectively as Exhibit B is a summary of each of those 4 cases. As with the West Virginia cases, we have identified the environmental damage report and the cause, if known. We have also provided a discussion of any enforcement or remedial action taken and the state or federal requirements that regulate the activity involved.

The documentation of these four cases indicated that in each case ODNR took action to correct the situation upon discovery of a problem. In each case, there is clear existing state and federal authority to regulate this conduct and to take appropriate enforcement action.

III. CONCLUSION.

A review of these damage cases indicates that in each of these states agencies have regulatory programs in place which authorize them to address the disposal of waste material associated with crude oil and natural gas exploration, development and

production. Not only do these agencies have the authority, it is obvious from this review that they exercise it.

As our comments dated January 14, 1987, indicated, Congress has made it clear that EPA must assess the adequacy of existing regulatory programs before determining whether a new program founded upon RCRA is justified. This investigation offers convincing authority for the fact that existing programs are adequate to protect human health and the environment.

EXHIBIT A

WEST VIRGINIA

DAMAGE ASSESSMENT CASES

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: June 30, 1970

2. ENVIRONMENTAL DAMAGE:

   Stream discharge resulting in discolored water. Slight odor and some crayfish killed due to mud.

3. OIL AND GAS OPERATION:

   Discharge from drilling pit.

4. ENFORCEMENT ACTION TAKEN:

   Unknown.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   This discharge would be prohibited under current statutory, regulatory and permit requirements.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: June 6, 1972

2. ENVIRONMENTAL DAMAGE:

Stream discharge resulting in death of aquatic life and stream discoloration.

3. OIL AND GAS OPERATION:

Failure of dike wall on drilling pit.

4. ENFORCEMENT ACTION TAKEN:

Unknown.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Discharges to surface streams are prohibited under current statues, regulations and permits. Pit wall construction is regulated under administrative regulations of the Department of Energy.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: September 20, 1972

2. ENVIRONMENTAL DAMAGE:

   Stream discharge with resulting fish kill.

3. OIL AND GAS OPERATION:

   Leaking drilling pit discharge to surface stream.

4. ENFORCEMENT ACTION TAKEN:

   Unknown.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Discharges to surface stream is prohibited by current statute, regulation and permit. Requirement to construct pits that do not leak are contained in regulations of the Department of Energy.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: January 25, 1973

2. ENVIRONMENTAL DAMAGE:

Stream discharge of unused well stimulation fluids resulting in fish kill.

3. OIL AND GAS OPERATION:

Direct discharge of stimulation fluid from frac tanks associated with well stimulation operations.

4. ENFORCEMENT ACTION TAKEN:

Criminal warrants issued for violating statutory requirements on stream pollution and for discharging without a permit.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

The discharge of frac fluid into a surface stream is prohibited under current statute, regulation and permits.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: May 5, 1973

2. ENVIRONMENTAL DAMAGE:

   Stream discharge of drilling fluids resulting in fish kill and turbid and muddy water.

3. OIL AND GAS OPERATION:

   Slippage of solid material into a drilling pit associated with a storage field project resulted in the overflow of liquids into the surface stream.

4. ENFORCEMENT ACTION TAKEN:

   Criminal warrants were to have been issued for the stream pollution and fish kill.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Such stream discharges are prohibited by current statutes, regulations and permits. Operator subject to assessment for the value of fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: September 6, 1973

2. ENVIRONMENTAL DAMAGE:

Stream discharge resulting in fish and crayfish kill.

3. OIL AND GAS OPERATION:

Drilling pit dike breached allowing release of drilling fluids into surface stream.

4. ENFORCEMENT ACTION TAKEN:

Operator assessed the cost to replace the gamefish or aquatic life killed.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Discharges to surface streams prohibited by current statute, regulation and permits. Statute authorizes DNR to recover the value of lost aquatic life.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: April 24, 1975

2. ENVIRONMENTAL DAMAGE:

Failure to reclaim pits resulting in safety problems.

Note: This complaint does not appear to be related to surface runoff or leachate but, rather, a safety problem associated with the pit itself.

3. OIL AND GAS OPERATION:

Reclamation of drilling pit.

4. ENFORCEMENT ACTION TAKEN:

Unknown.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Current statutes, regulations and permits require reclamation of all drilling pits in accordance with technical guidelines of the Department of Energy. Reclamation bonds are required to be posted to assure proper reclamation.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: May 24, 1976

2. ENVIRONMENTAL DAMAGE:

Discharge to a surface stream resulting in the death of "4 small minnows."

3. OIL AND GAS OPERATION:

Discharge of 20 to 25 barrels of salt water from a tank (presumably for oil storage) resulting from the cracking of a plastic line at the base of the tank.

4. ENFORCEMENT ACTION TAKEN:

Unknown.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Stream discharges are prohibited by current statute, regulation and permit. 40 C.F.R. Part 112 requires the diking of tanks of specified size.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: September 6, 1976

2. ENVIRONMENTAL DAMAGE:

   Stream discharge resulting in aquatic life death.

3. OIL AND GAS OPERATION:

   Salt water spill (of unknown origin).

4. ENFORCEMENT ACTION TAKEN:

   Operator pleaded guilty to criminal charges of stream pollution and failure to report a spill.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Stream discharges are prohibited under current statutes, regulations and permits. Failure to report a spill is prohibited under current statute and regulations.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: September 20, 1976

2. ENVIRONMENTAL DAMAGE:

   Stream discharge resulting in fish kill.

3. OIL AND GAS OPERATION:

   Discharge from gas well drilling operation.

4. ENFORCEMENT ACTION TAKEN:

   Criminal charges filed for failing to report a spill and the company required to pay the replacement cost for the fish killed.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Stream discharges prohibited by current statute, regulation and permits. Failure to report a spill prohibited by current statute and regulation; operator obligated to pay the cost of replacing fish killed in such a spill.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: June 23, 1977

2. ENVIRONMENTAL DAMAGE:

Stream discharge of gasoline and fuel oil resulting in fish kill.

Note: This discharge appears related to petroleum refinery operations and not to oil and gas well drilling, exploration and production.

3. OIL AND GAS OPERATION:

Discharge of gasoline and fuel oil from oil refinery.

4. ENFORCEMENT ACTION TAKEN:

Company required to pay fish replacement cost.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Discharges to surface streams of this type prohibited by current statute and regulation. Fish damage from such discharges recoverable against the company.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: April 20, 1979

2. ENVIRONMENTAL DAMAGE:

   Stream discharges resulting in fish kill.

3. OIL AND GAS OPERATION:

   Drilling pit breach.

4. ENFORCEMENT ACTION TAKEN:

   Criminal warrant may have been issued.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Stream discharges of this kind are prohibited by current statute, regulation and permit.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: August 13, 1979

2. ENVIRONMENTAL DAMAGE:

Stream discharge resulting in discoloration and dead fish.

3. OIL AND GAS OPERATION:

Discharge from drilling pit of drilling fluids (mostly drilling detergents).

4. ENFORCEMENT ACTION TAKEN:

Some consideration was given to bringing criminal action against the operator as well as the possibility of assessing the operator for the value of the aquatic life that was killed as a result of the spill.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Stream discharges of this kind are prohibited by statute, regulation and permit. Operators' obligated to pay for the replacement value of fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: August 21, 1979

2. ENVIRONMENTAL DAMAGE:

Discharge to surface stream resulting in death of minnows and discoloration.

3. OIL AND GAS OPERATION:

Operator opened a valve on an oil storage tank allowing the release of salt water oil and detergent.

4. ENFORCEMENT ACTION TAKEN:

Criminal warrant issued against operator for negligent pollution.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Stream discharges of this kind are prohibited by statute, regulation and permit. 40 C.F.R. Part 112 requires diking of facilities of certain size. Statutes authorize assessment of replacement value for dead aquatic life.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: May 23, 1980

2. ENVIRONMENTAL DAMAGE:

Stream discharge resulting in fish kill.

3. OIL AND GAS OPERATION:

Heavy rainfall caused drilling pit to overflow causing release of stimulation fluid contained in the pit.

4. ENFORCEMENT ACTION TAKEN:

Company was cited for unlawful discharge.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Such discharge prohibited by current statute, regulation and permit. Current regulations and permits require the operator to divert stormwater runoff away from the drilling pit. Current regulations and permit require the operator to maintain adequate freeboard and to construct additional drilling pits as necessary to prevent overflow. Current statutes authorize an assessment to be imposed on the operator for the replacement value of aquatic life killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: June 23, 1980

2. ENVIRONMENTAL DAMAGE:

Stream discharge resulting in the death of 7 minnows.

3. OIL AND GAS OPERATION:

Breach of drilling pit wall resulting in release of material to surface stream.

4. ENFORCEMENT ACTION TAKEN:

Operator cited with a criminal warrant for stream pollution and assessed a fine.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Such stream discharges are prohibited by current statute, regulation and permit. Operator subject to assessment for replacement value of aquatic life killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: May 14, 1980

2. ENVIRONMENTAL DAMAGE:

   Stream discharge with resulting fish kill.

3. OIL AND GAS OPERATION:

   Frac water leaked from a drilling pit.

4. ENFORCEMENT ACTION TAKEN:

   Operator assessed the replacement cost for aquatic life killed as a result of the spill.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Spills of this kind are prohibited by current statute, regulation and permit. Operator subject to assessment for the value of fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: July 16, 1980

2. ENVIRONMENTAL DAMAGE:

Stream discharge resulting in fish kill.

3. OIL AND GAS OPERATION:

Discharge of frac water from tanks from discharge of unused frac fluid from tanks.

4. ENFORCEMENT ACTION TAKEN:

Operator cited with criminal warrants for stream pollution and assessed the replacement value for aquatic life.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Such discharges are prohibited by current statute, regulation and permit. Operator subject to assessment for the value of fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: August 11, 1980

2. ENVIRONMENTAL DAMAGE:

   Stream discharge resulting in fish kill.

3. OIL AND GAS OPERATION:

   Drilling pit discharge of frac fluid.

4. ENFORCEMENT ACTION TAKEN:

   Company cited for a criminal warrant for unlawful stream discharge and assessed replacement cost for the fish kill.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Discharges of this kind prohibited by current statute, regulation and permit. Operator subject to assessment for the replacement value of fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: September 13, 1980

2. ENVIRONMENTAL DAMAGE:

Stream discharge resulting in fish kill.

3. OIL AND GAS OPERATION:

Stimulation of flowback from a well which directly entered a stream inasmuch as the operator did not have a pit constructed to receive that flowback.

4. ENFORCEMENT ACTION TAKEN:

Operator cited with a criminal warrant for stream pollution.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Discharges of this kind are prohibited under current statute, regulation and permit. Current regulations and permits require stimulation flowback fluids to be directed to a pit for control and treatment prior to land application or other authorized disposal methodology. Operator also subject to replacement value for any fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: September 27, 1980

2. ENVIRONMENTAL DAMAGE:

Stream discharge with resulting fish kill.

3. OIL AND GAS OPERATION:

Discharge from a waste pit.

4. ENFORCEMENT ACTION TAKEN:

Criminal warrant issued against the operator.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Discharges of this kind are prohibited by current statute, regulation and permit. Operator subject to replacement cost for fish kill.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: October 1, 1980

2. ENVIRONMENTAL DAMAGE:

   Stream discharge resulting in fish kill.

3. OIL AND GAS OPERATION:

   Salt water drainage from an oil storage tank.

4. ENFORCEMENT ACTION TAKEN:

   Criminal prosecution undertaken against the operator for prohibited stream pollution.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Discharges of this kind are prohibited by current statute, regulation and permit. Operator is subject to replacement cost for fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: March 16, 1981

2. ENVIRONMENTAL DAMAGE:

Discharge of oil film to surface stream.

<u>Note</u>: There is no indication of any environmental harm.

3. OIL AND GAS OPERATION:

Oil seeping into a surface stream from an old drilling pit that was filled in while containing a quantity of oil.

4. ENFORCEMENT ACTION TAKEN:

Department of Natural Resources took no criminal action against this operator but, instead, worked with the operator to initiate remedial action.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Discharges of this kind are prohibited by current statute, regulation and permit. All reclamation requirements must be undertaken in accordance with regulations and technical guidelines of the Department of Energy. Current permits prohibit the placement of refined oils in drilling pits and require all crude oil to be skimmed from the surface of drilling pits prior to discharge of pit contents.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: July 13, 1981

2. ENVIRONMENTAL DAMAGE:

   Stream discharge resulting in fish kill.

3. OIL AND GAS OPERATION:

   Discharge of brine from an oil stock tank battery perhaps resulting from a faulty brine line.

4. ENFORCEMENT ACTION TAKEN:

   None indicated.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Discharges of this kind are prohibited by current statute, regulation and permit. Operator subject to assessment for fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: September 27, 1981

2. ENVIRONMENTAL DAMAGE:

   Stream discharge resulting in fish kill.

3. OIL AND GAS OPERATION:

   Salt water discharge from an oil storage tank caused by leaking valve.

4. ENFORCEMENT ACTION TAKEN:

   Operator cautioned and advised that criminal action would be taken if the situation reoccurred.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Stream discharge of this type is prohibited by current statute, regulation and permit. Operator subject to assessment for the value of fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: October 13, 1981.

2. ENVIRONMENTAL DAMAGE:

Dead and sick cattle alleged by the owner to have been caused by produced fluid from a gas well.

Note: Complaint form is inconclusive in attributing the alleged damage to the gas well.

3. OIL AND GAS OPERATION:

Produced fluid from gas well.

4. ENFORCEMENT ACTION TAKEN:

Unknown.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Discharges of produced fluid to surface streams are prohibited under current statute, regulation and permit.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: November 22, 1981

2. ENVIRONMENTAL DAMAGE:

Stream discharge resulting in fish kill.

3. OIL AND GAS OPERATION:

Discharge of well stimulation flowback fluid to a surface stream at a site where the pit had already been reclaimed.

4. ENFORCEMENT ACTION TAKEN:

Enforcement action appears to have been contemplated by DNR.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Such stream discharges of stimulation flowback fluid are prohibited by current statue, regulation and permit. Under the current applicable permit, well stimulation fluid would be required to be directed to a pit for treatment prior to discharge to land application. The operator is subject to assessment for the value of fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: February 25, 1982

2. ENVIRONMENTAL DAMAGE:

Leaching of oil into a surface stream.

3. OIL AND GAS OPERATION:

Leaching of oil from a reclaimed drilling pit associated with a gas well.

4. ENFORCEMENT ACTION TAKEN:

Remedial action imposed under the direction of the U.S. Forest Service.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Stream discharges of oil prohibited under current statutes, regulations and permits. Operator subject to assessment for the value of fish kill. Regulations and permits specify the manner in which pits are reclaimed and require oil to be removed from the surface of pits prior to discharge.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: March 12, 1982

2. ENVIRONMENTAL DAMAGE:

Discharge to surface stream resulting in 2 dead cattle. The DNR complaint form does not establish a cause or connection between the death of the cattle and the discharge alleged.

3. OIL AND GAS OPERATION:

Discharge from a pit containing well fracturing fluid.

4. ENFORCEMENT ACTION TAKEN:

Legal action anticipated.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Stream discharges of this type prohibited by current statute, regulation and permit.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: August 20, 1982

2. ENVIRONMENTAL DAMAGE:

   Stream discharge resulting in fish kill.

3. OIL AND GAS OPERATION:

   Discharge from a drilling pit and discharge from a tank containing stimulation fluids brought to the surface as the result of swabbing operations.

4. ENFORCEMENT ACTION TAKEN:

   Criminal charges filed for causing pollution.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Stream discharges of this kind prohibited by current statute, regulation and permit. All frac water is required by current regulation and permit to be directed to a pit for treatment prior to disposal by land application. Operator subject to assessment for replacement value of fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: January 6, 1983

2. ENVIRONMENTAL DAMAGE:

   Discharge to a surface stream resulting in fish kill.

3. OIL AND GAS OPERATION:

   Discharge of produced water from an oil storage tank.

4. ENFORCEMENT ACTION TAKEN:

   None indicated.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Stream discharges of this kind prohibited by current statute, regulation and permit. 40 C.F.R. Part 112 requires that tanks of certain size be diked. Operator subject to assessment for the value of fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: June 8, 1983

2. ENVIRONMENTAL DAMAGE:

Stream discharge resulting in fish kill.

3. OIL AND GAS OPERATION:

Contents of drilling pit discharged when bulldozer operator filled-in two drilling pits as part of reclamation.

4. ENFORCEMENT ACTION TAKEN:

Three criminal warrants were issued for failure to maintain adequate freeboard, failure to report a spill, and discharging a material harmful to aquatic life.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Such discharges are prohibited by current statute, regulation and permit. As part of pit reclamation requirements, current regulation and permit require all fluids to be discharged prior to backfilling of the pit. Operator subject to assessment for the value of fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: September 13, 1983

2. ENVIRONMENTAL DAMAGE:

Discharge to surface stream resulting in fish kill.

3. OIL AND GAS OPERATION:

Leak of drilling fluids from a drilling pit inappropriately constructed.

4. ENFORCEMENT ACTION TAKEN:

Criminal warrants issued for leakage from the pit and operator assessed the value of fish killed.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Stream discharges of this type prohibited by current statute, regulation and permit. Operator subject to assessment for value of fish killed. Regulations and permits require pits to be constructed so as not to leak.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: February 28, 1984

2. ENVIRONMENTAL DAMAGE:

   Discharge to surface stream resulting in fish kill.

3. OIL AND GAS OPERATION:

   Ruptured dike wall associated with a drilling pit causing stream discharge.

4. ENFORCEMENT ACTION TAKEN:

   Criminal prosecution contemplated.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

   Stream discharges of this type prohibited by current statute, regulation and permit. Regulations and permits require pits to be constructed in a manner to assure their integrity. Operator subject to assessment for the value of fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: June 8, 1984

2. ENVIRONMENTAL DAMAGE:

Discharge into the ground and into a surface stream used as a water supply. Some dead vegetation noted but no fish kill apparent.

3. OIL AND GAS OPERATION:

Drilling fluids escaped into the groundwater from a drilling pit being managed by an operator in connection with an experimental regulatory program developed by the Department of Natural Resources.

4. ENFORCEMENT ACTION TAKEN:

Enforcement action not anticipated due to circumstantial nature of evidence.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Discharges of this type prohibited by current statute, regulation and permit. Current regulations and general permit specifies a comprehensive program for the treatment, discharge and reclamation of drilling pits.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: June 25, 1984

2. ENVIRONMENTAL DAMAGE:

Oil on ground and seeping from small pit.

3. OIL AND GAS OPERATION:

Discharge of oil brought to the surface in the course of plugging an abandoned well under contract with the West Virginia Department of Mines.

Note: This case does not appear to be related to the exploration, development, or production of oil and gas.

4. ENFORCEMENT ACTION TAKEN:

None contemplated inasmuch as there was no discharge to waters of the state.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Discharges to groundwater are prohibited by statute unless authorized by permit.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: July 14, 1984

2. ENVIRONMENTAL DAMAGE:

Contamination of a spring as a result of oil contamination of groundwater.

3. OIL AND GAS OPERATION:

Investigation report identifies possible sources for the oil as being well blowout, or faulty casing, or oil from old pits. The report also raised questions about whether the oil might be coming from abandoned wells located nearby. The report appears to be inconclusive as to the source of the oil.

4. ENFORCEMENT ACTION TAKEN:

None indicated.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Current statutes, regulations and permits prohibit the discharge of oil to groundwater or to surface streams.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: September 18, 1984

2. ENVIRONMENTAL DAMAGE:

Discharge to surface water resulting in fish kill.

3. OIL AND GAS OPERATION:

Seeping of the contents of a drilling pit into a farm pond.

4. ENFORCEMENT ACTION TAKEN:

Criminal action contemplated.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Discharges of pits into surface streams prohibited by current statutes, regulations and permits. Regulations and permits require drilling pits to be constructed so as not to leak. Operator subject to assessment for the value of fish killed.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: January 17, 1985

2. ENVIRONMENTAL DAMAGE:

Last of 4 complaints (the others occurring on September 13, 1984, February 24, 1981 and November 17, 1980) by the same landowner complaining about adverse effects on cattle as a result of unidentified oil and gas well operation. It is apparent from a review of the complaint form that there was little evidence to substantiate these complaints.

3. OIL AND GAS OPERATION:

Unspecified.

4. ENFORCEMENT ACTION TAKEN:

None taken.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Stream discharges are prohibited under current statutes, regulations and programs. An operator is obligated to reclaim a pit within 6 months after completion of drilling operations.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: March 7, 1985

2. ENVIRONMENTAL DAMAGE:

Soapy water present in a surface stream.

3. OIL AND GAS OPERATION:

Complaint assumed that problem was resulting from surface runoff from a gas well or oil storage tank area.

4. ENFORCEMENT ACTION TAKEN:

No enforcement action taken, however, operator was requested to undertake remedial steps to minimize runoff.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Stream discharge of this type prohibited by current statute, regulations and permit. At time of reclamation, operator is obligated to reclaim pits in accordance with regulations and permits of the Department of Energy.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: March 18, 1985

2. ENVIRONMENTAL DAMAGE:

Dead cattle from drinking drilling pit water.

3. OIL AND GAS OPERATION:

Operator was maintaining a drilling pit associated with the drilling of a gas well. These activities were being undertaken in accordance with the experimental development of a general permit for drilling pit discharges.

4. ENFORCEMENT ACTION TAKEN:

Agency contemplated enforcement action for discharging material from the pit into a surface stream.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Such discharges to surface streams are prohibited by current statute, regulation and permit. Under current general permit, operators are required to fence all drilling pits as necessary to prevent animals from entering the drilling pit. The facts surrounding this complaint do not appear to be related to surface runoff or leachate.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: July 4-11, 1985

2. ENVIRONMENTAL DAMAGE:

Three dead cattle after drinking water from a spring near a gas well.

3. OIL AND GAS OPERATION:

While a gas well was located nearby the spring where the cattle died, there was no substantiation that discharge from the well resulted in the death of the animals.

4. ENFORCEMENT ACTION TAKEN:

None indicated.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Discharges of produced fluid to surface water is prohibited under current statute, regulation and permit.

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WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: April 4, 1986

2. ENVIRONMENTAL DAMAGE:

Three dead cattle as a result of drinking water directly from a drilling pit.

3. OIL AND GAS OPERATION:

Operator maintaining drilling pits in good condition pursuant to the current general permit for drilling fluids in West Virginia.

Note: The facts surrounding this complaint do not appear to be related to surface runoff or leachate.

4. ENFORCEMENT ACTION TAKEN:

None indicated.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Operator is required under existing general permit to fence drilling pits as necessary to keep animals from entering those pits.

WEST VIRGINIA DEPARTMENT OF NATURAL RESOURCES
DIVISION OF WATER RESOURCES
COMPLAINT

1. DATE: June 13, 1986

2. ENVIRONMENTAL DAMAGE:

Vegetation killed as a result of land application of pit contents.

3. OIL AND GAS OPERATION:

Land application of pit contents pursuant to general permit.

4. ENFORCEMENT ACTION TAKEN:

No criminal penalties were sought, however, the operator was requested to take remedial action by fertilizing and liming the affected area. DNR reports that the vegetation has fully recovered as a result of remedial action.

5. CURRENT APPLICABLE REGULATORY REQUIREMENTS:

Current general permit places limitations on the concentration of pollutants that can be discharged through a land application disposal technique. These parameters are being reviewed in the context of the reissuance of the general permit and adjustments to these conditions are expected either to reduce the overall chloride concentration that will be allowable under the permit or to establish a total loading of chloride that will be permitted to an acre of land. Discharges in excess of these limits are subject to enforcement action.

SUMMARY OF COMMENTS OF
THE AMERICAN PETROLEUM INSTITUTE
ON THE
U.S. ENVIRONMENTAL PROTECTION AGENCY'S
"WASTES FROM THE EXPLORATION, DEVELOPMENT AND PRODUCTION
OF CRUDE OIL, NATURAL GAS AND GEOTHERMAL ENERGY"
Interim Report; April 30,1987

The American Petroleum Institute (API) appreciates the opportunity to submit comments on the Interim Report of the Environmental Protection Agency (EPA) addressing the wastes, management practices, and regulatory programs associated with the exploration for and production of oil and gas. The report, mandated under Section 8002(m) of the Resource Conservation and Recovery Act (RCRA), is a substantial undertaking in terms of scope, content and importance.

There are 1.25 million production sites in the United States made up of approximately 842,000 oil and gas wells, 210,000 tank batteries, 168,000 injection wells and 13,000 water stations located in 38 states. The oil and gas wells produce 8.4 million barrels of crude oil and 44 billion cubic feet of natural gas daily. The industry complies, on a daily basis, with both state and federal regulations designed to address the proper handling and discharge of wastes generated during drilling and production operations.

The industry is firmly committed to assisting EPA in its efforts to insure that the final report is factual and contains the best possible data from which sound conclusions may be drawn.

The extremely short review period has limited API's ability to investigate some aspects of the Interim Report. However, the attached submission provides the industry's comments on a chapter-by-chapter basis.

API will continue to develop pertinent information for EPA's use in revising and finalizing this important study. The following summary highlights API's major concerns with its Interim Report.

CHAPTER 1 -- Overview of the Oil and Gas Industry

In Chapter 1, EPA's contractor has produced a reasonably accurate assessment of oil and gas operations. A large number of API's comments on the October 31, 1986 technical report have been included in the Interim Report to produce a more credible analysis of the industry's drilling and production activities. Nonetheless, there are a number of significant changes and additions to Chapter 1 which still need to be made. These revisions are addressed in detail in Attachment 1 of the API comments, however several major issues deserve comment in this summary.

First, an accurate estimation of drilling fluid volumes is crucial to the credibility of this study. This estimate will directly affect both the expected volume of waste (including the volume of contaminants in the waste), the risk assessments and the economic impact calculated for current and alternative waste management practices in Chapters 4, 5, and 6.

API's review of Chapter 1 discloses that the report has overstated drilling fluid volumes by a factor of seven, when EPA's contractor estimates are compared to data gathered by API in 1986 as a part of an extensive industry survey. The contractor based its estimates on a limited number of pit sizes of a typical dimensions. On page I-33, the report states "Currently, the API data are not available to the agency for evaluation". Data to substantiate API's conclusion were furnished to EPA on April 15, 1987. Details are contained in Attachment 1.

Second, although Chapter 1 recognizes that the injection of produced water is a standard practice in the oil industry, it contains several inaccuracies in its characterization of these fluids. Produced water volumes used in additional recovery operations are a necessary part of oil recovery process and are not discarded as "waste". These volumes should not be included when performing the evaluations discussed in Chapters 4, 5, and 6. It should be noted that the injection of produced water for secondary oil recovery as well as water disposal is regulated by both states and EPA in accordance with the provisions of the underground injection control (UIC) program of the Safe Drinking Water Act.

CHAPTER 2 -- Current and Alternative Practices

The stated intent of Chapter 2 of the report is to address the current and alternative waste management practices of the oil and gas industry, as prescribed in RCRA Section 8002(m). The introductory section of the chapter properly recognizes two important considerations. First, "[v]irtually every waste management practice that exists can be considered current in one specific situation ... [and] practices that are routine in one location may be considered innovative or alternative elsewhere ..." (p. 2). Second, the report states that the federal and state regulation of waste management should reflect physical and geological variations among different regions of the nation. However, rather than incorporating these two considerations in the analysis of waste management practices, the bulk of the chapter is devoted to a criticism of state and federal programs for a lack of uniformity of requirements and an implicit endorsement of particular alternative methods of waste management, such as closed loop mud management systems or centralized commercial disposal facilities. A fundamental weakness of the entire chapter is a lack of support for the conclusions advanced. Detailed information on API's comments is contained in Attachment No. 2.

For example, the advantages and disadvantages of various disposal methods are expressed in very general terms. There is little

technical discussion of how each method may or may not be appropriate for specific types of physical and geological conditions. Instead of a range of conditions being addressed, the analysis tends to center on the effectiveness of a particular management practice to handle worst-case, hypothetical conditions. Accordingly, the chapter provides little practical guidance in the determination of appropriate waste management for specific locations.

In part, the conclusions of the Chapter may be attributable to an implicit assumption that drilling fluids and produced waters are "hazardous wastes". Certainly it is premature for EPA to draw a conclusion that these wastes should be referred to as hazardous. For example, statements in the Chapter suggest drilling fluids are "hazardous" because they contain additives or constituents which may be contained on lists and Appendices in 40 C.F.R. Part 261 of the RCRA Subtitle C regulations. Such statements, though, misconstrue the entire thrust of the RCRA Subtitle C program, because the mere presence of a "hazardous constituent" does not render a particular waste as "hazardous waste" unless it: (1) causes the waste to fail the RCRA characteristic tests, such as the extractive procedure (EP) toxicity characteristic or (2) appears in the waste due to the mixing of listed waste materials (F, U, P or K lists) with the waste material. Moreover, the report is misleading in its discussion of the additives of drilling muds, because these chemicals are part of a commercial product, not a waste, and in many instances, will either be chemically altered during their use in the drilling fluid or will not be released into the environment in the form of a listed "hazardous constituent". Further, it should be understood such additives are not present in all mud systems at all times.

Don't imply that these wastes are hazardous

The chapter also strongly criticizes existing regulatory programs such as those adopted pursuant to the Clean Water Act (CWA) and Safe Drinking Water Act. Many statements suggest a lack of understanding of the National Pollution Discharge Elimination System (NPDES) and Underground Injection Control (UIC) programs. In particular, the CWA's NPDES program is criticized for states issuing permits. The report should recognize that states issue interim permits because of EPA's failure to act. For balance, it should address the potentially harmful impacts that could occur if the states did not require interim permits. The discussion of the beneficial use provisions of the NPDES program is also conclusory and subjective. The statement that "it is rare that produced waters have low enough chloride levels (< 500 ppm) to be used directly for beneficial purposes" is simply too broad to be accurate. Many wells produce water with chloride levels that are less than 500 ppm and many types of livestock can safely drink water with chloride content in excess of 1000 ppm. In fact, in certain arid parts of the country, landowners are dependent upon these produced waters for their main source of livestock water.

The chapter criticizes the UIC program, but again little factual evidence is cited. The clear assumption running throughout the critique is that a lack of uniformity among State requirements is a shortcoming of the program. The benefit of "uniformity" is merely

presumed rather than proven. In addition, there is no evaluation of the actual reasons for and possible benefits of the differentiation of requirements among the States. Section 1421 of the Safe Drinking Water Act mandates the consideration of local geological, hydrological and other physical factors in prescribing UIC requirements. This statutory requirement, is not mentioned in the report. Instead, instances where the program allows flexibility in prescribing particular requirements are presented as if they represent "loopholes". The report also fails to recognize that these provisions are only available when the particular practice does not endanger underground sources of drinking water.

Overall, Chapter 2 creates the erroneous impression that the NPDES and UIC programs are principally "state" programs and that any perceived problems are the result of state action or inaction. In fact, these programs are federal programs, administered by EPA. In certain producing states, EPA regional offices directly implement and enforce the programs. There are also provisions in both statutes, allowing EPA to take over administration of inappropriately administered state programs. Finally, EPA can directly enforce federal and state requirements without prior state approval.

The programs promulgated to implement the Clean Water Act and Safe Drinking Water Act have, on the basis of practical experience, undergone substantial revision and represent major initiatives to protect human health and the environment. The effectiveness of their requirements was not the focus of Congress in adopting RCRA Section 8002(m). Nor should these programs be criticized on the basis of speculative innuendo. Chapter 2 provides no factual basis to support its numerous allegations of program ineffectiveness. This chapter requires substantial revision to ensure its objectivity.

Chapter 3 -- Oil and Gas Damage Cases

EPA is mandated by Congress to identify any examples of practices that have caused environmental or health damages. API has done an extensive review and analysis of Chapter 3 and Appendix C that contains 228 alleged damage cases which the contractor has indicated passed its "test of proof". Shortly after receiving copies of the alleged damage cases, API prepared an analysis of the case summaries to determine whether, "on their face", they identified legitimate concerns. This analysis that indicated major flaws in methodology and factual content was provided to EPA on May 7, 1987.

Thereafter, a significant number of the cases were reviewed in great detail by experienced industry technical and/or regulatory personnel. The documentation cited by EPA's contractor was consulted, files of regulatory agencies were examined and, importantly, parties (including the operator) involved in many of the cases were contacted to obtain their account of the alleged damage cases.

API's overall conclusions based upon this thorough review of Chapter 3 of the Interim Report and the 228 alleged damage cases are as follows:

(1) The broad conclusions contained in Chapter 3 are not factually supported.

(2) EPA's contractor did not conduct a thorough review of the alleged damage cases. This is evident by the numerous factual errors, and by the sweeping, remarks made with respect to the state agencies in the summaries (<u>e.g. see</u> Damage Cases TX 25 and 29 in Attachment 8).

(3) Even taking the reported damage case summaries "at face value", very few, of the alleged damage cases would arguably support the need for incremental federal regulation. Indeed, when the 228 damage cases covering many years of operations in 13 states which account for approximately 1 million of the 1.25 million production sites in the nation, there is clearly little evidence of environmental damage associated with oil and gas operations.

The most significant result of API's detailed analysis of 228 alleged damage cases contained in Appendix C is the fact that 224 clearly do not provide any basis for additional regulation since they involve: non-RCRA issues; non-current practices; violations of existing regulations; unsubstantiated damage or cause of "damage"; or pending cases. Regulations are either being developed or are under consideration for the remaining four cases. The following table indicates for these five categories, the number of cases which are not relevant to the need for additional federal regulation:

Category*	Number of Cases**
Non-RCRA Issues (e.g. production practices, erosion, oil spills and NPDES discharges exempt under RCRA)	45
Non-Current Practices	67
Violations of Current Regulations	136
Unsubstantiated Cause/Damage	81
Pending Cases	18

* Attachment No. 3 describes the various categories which API feels are clearly not relevant to this study and reasons for those conclusions.

** Several of the 224 cases fall into more than one category, e.g. it may be a non-current practice and a violation. Consequently, the table when added, will exceed 224.

In particular, it should be noted that even when the damage case summaries indicate that an operator had been in violation of current regulations, there were administrative or enforcement actions by the state regulatory agency in 126 of the 136 cases. This clearly refutes the allegations in Chapter 3 that state oil and gas agencies have been deficient in their enforcement responsibility. It also reflects the lack of thoroughness in the preparation of the damage case summaries, since the contractor failed to find or disclose a substantial number of the administrative and enforcement actions by the state agencies. For example, EPA damage cases for Louisiana identified only 12 administrative/enforcement actions whereas API's review documented 36.

One other observation is pertinent. It is clear from reading the 228 alleged damage case summaries that EPA's contractor was careless in its investigation and presentation of this material. API has been unable to find a single case where EPA's contractor contacted the operator involved to determine their side of the story. It is also evident that EPA's contractor failed to adequately consult with state regulatory agencies - which would have the most significant amount of information about many cases. API's analysis indicated that most case summaries are seriously inaccurate.

Accordingly, there is no basis for the following conclusions cited in Chapter 3 of the report:

1) "Health and environmental damages caused by oil and gas operations appear to be significant, widespread, and in need of correction". (p. 8) As discussed herein, a careful review of the damage cases belies this unsupported conclusion.

2) "There is convincing circumstantial evidence that serious health effects, such as cancer and other fatal diseases, have been caused or are potentially caused by oil and gas activities." (p. 8) The evidentiary support for this serious allegation is wholly lacking in the damage cases. There are very few cases that even address possible human health effects. Moreover, in one damage case (LA 68) which reports allegations of cancer, heart problems, and other health effects resulting from oil and gas operations, the EPA contractor states: "case settled out of court for an undisclosed sum". API's investigation of the case discloses that a federal district court found for the defendant oil company by granting a summary judgement in the action and also ordered the plaintiff to pay court costs. Neither the report nor the damage cases contain any evidence which could even loosely be termed as "circumstantial" with regard to health effects associated with oil and gas activities. Instead, the report engages in unsupported speculation about the reasons for the lack of identified health effects. Clearly, the report has failed to identify "documented damage cases that prove or have caused..."

3) "Damages are caused by non hazardous as well as hazardous substances." (p. 9) The contention that drilling muds are "hazardous" is based principally upon a list of possible additives. As discussed earlier, the mere presence of a "hazardous constituent" in a waste, much less a product, cannot support a conclusion that a material is "hazardous waste". The results of the API field sampling program and the chemical changes which occur during the use of the fluids indicate these materials are not hazardous if properly managed. The part of

this conclusion associated with "non-hazardous" substances is related to the fact that produced water contains salts that if improperly managed cause damage. This fact has long been recognized and is one of the reason produced waters are managed and disposed of in accordance with numerous state and EPA regulations.

4) "Past practices can both cause and contribute to current damages." (p. 10) This conclusion is not supported by the damage cases. In addition, it violates the stated objective of the Chapter to address current practices and not to determine if new regulations are required to correct past practices, which if used today would violate current state and federal regulation.

5) "State standards vary widely in scope and content." (p. 11) It is true that state standards vary widely in scope and content. This reflects the influence of different geography and geology on production operations as well as differing environmental protection needs. Both EPA and state regulations governing NPDES permitted discharges recognize the need for the variance in standards. Neither Chapter 2 nor Chapter 3 demonstrate that there is any reason to believe that environmental risks are increased when state standards vary. Indeed, Chapter 2 recognizes the need for variation. In addition, it should be noted that this conclusion was reached before Chapter 7, "Summary of State and Federal Regulations," was available.

6) "Implementation and enforcement of state requirements is seriously deficient." (p. 12) API's review indicates that of the 136 cases which were violations of state and federal regulations there were 126 administrative or enforcement actions. The high number of such actions indicates that states have effective regulatory programs with good enforcement records.

7) "State regulatory programs are, as a rule, seriously under funded and understaffed." (p. 12) The high number and ratio of administrative and enforcement actions relative to damage cases does not support this conclusion. Also a large part of the regulatory program dealing with the largest waste volume (produced water) is funded primarily by EPA through the UIC program, and administered by the EPA's Office of Safe Drinking Water. EPA has the authority to fund solid waste management programs administered by states, as they may pertain to oil and gas wastes, under Subtitle D of RCRA. Consequently, API would suggest that if EPA believes that state programs are "seriously underfunded and understaffed" that EPA should take appropriate action under its existing programs. Additional regulatory requirements will not solve, and may aggravate, this perceived problem.

8) "Many State regulatory agencies face conflicting incentives and responsibilities." (p. 13) This conclusion argues that revenues for regulatory agencies come from direct or indirect taxes on petroleum operations that create an inherent conflict of interest. Supporting information is not included in the damage cases. Generally, agency budgets are set by state legislatures or funded by the EPA.

9) "In some States, economic reliance on oil industry revenues increases public tolerance of environmental damages." (p.13) This conclusion argues that citizens may be discouraged from complaining about damages out of cynicism or fear of job reprisals. Supporting information for this conclusion is not contained in the damage cases.

Attached are the following additional API documents addressing Chapter 3 and the 228 alleged damage cases contained in Appendix C of the Interim Report:

(1) API's overall damage case summary (Attachment 4).

(2) An extensive API summary of the 228 alleged damage cases based upon API's detailed review of the damage cases (Attachment 5).

(3) An extensive API summary of the 228 cases based upon API's "face value" review of the damage case summaries (Attachment 6). These data were submitted to EPA on May 7, 1987.

(4) API's comments on the zone by zone conclusions contained in Chapter 3 (Attachment 7).

(5) API's detailed corrections to the damage cases summaries (with additional documentation where appropriate) based upon API's detailed review thereof (Attachment 8).

(6) A summary of some of the more significant examples illustrating that EPA's contractor did not perform a thorough and accurate review of the damage cases (Attachment 9).

CHAPTER 4 -- Human Health and Environmental Health Risk Assessment

In developing the scope for its study of risk, EPA has properly focused on waste management activities and the issue of the RCRA exemption for exploration and production wastes. In addition, EPA has focused on the more common types of wastes and waste management practices, particularly in the case of drilling fluid wastes. This framework will allow the Agency to address the issue of whether it is necessary to extend the RCRA regulations to exploration and production wastes to protect human health and the environment. API's detailed comments on Chapter 4 are contained in Attachment 10.

It is essential that EPA ensure that its risk assessments are based on appropriate modeling and experimental evidence. In addition, any assessment must take into account the likelihood of such damage by considering the frequency and occurence of such events. It is essential, therefore, that the damage cases used be appropriate and verified.

EPA's contractor has chosen a risk model (the LLM Risk and Cost Analysis Model) that is unvalidated and has not been peer reviewed. Therefore it should not be used as a regulatory tool. This problem is compounded by the approach of allowing the limitations of the LLM model to guide the study rather than tailoring the modeling approach to the problems being addressed. Repeatedly, the input parameters for this model have been developed on the basis of limited data,

hypothetical worst-case assumptions, and modelling limitations, in many cases neglecting valuable data available from API, the open literature, or other EPA programs.

Two examples of the poor quality of the data are the injection well risk scenarios and the health-based standards. The failure scenarios for underground injection were based, according to the report, on professional judgement rather than on any actual data. The assumptions that: 1) 25 square centimeters is a representative casing leak size; 2) all levels of protection on a well will fail simultaneously; 3) some permitted injection wells do not meet design criteria; and 4) testing systems in place will not detect failures are arbitrary, unsupported, and in API's view, do not represent good professional judgment. Yet, there is no discussion of how EPA will quantify the resultant large uncertainty in model results, or even whether such an effort will be made. The health-based standards incorporated in the model are insufficiently documented in the report. In the case of carcinogenic potency of arsenic, the model ignores forthcoming findings of EPA's own Risk Assessment Forum that this potency is actually an order of magnitude less than that assumed in the model.

There are other examples of inadequacies in model data. These include data describing leaching of water and waste constituents from pits, migration through ground water, constituent uptake on soils and sediment, human response to toxic or carcinogenic substances, and water quality criteria for waste constituents in aquatic ecosystems. Data are available from API and other sources that would allow EPA to upgrade these model inputs. Data inadequacies for many aspects of the model and suggested improvements are described in further detail in Attachment 4 to these comments.

The inappropriateness of the risk model and a neglect of available data, combined with significant inaccuracy and uncertainty in input parameters, will make model results highly questionable. Without sensitivity studies or other evaluations to quantify uncertainty in risk modeling results, the results cannot be useful or meaningful.

API encourages EPA to improve and verify the LLM model, to use data available from API, the literature and other sources to improve estimates of input parameter values, and to quantify the uncertainty in model risk calculations so that the results can be used in the context of their likely accuracy.

CHAPTER 5 -- Costs of Baseline and Alternative Waste Management Practices for the Onshore Oil and Gas Industry

Chapter 5 proposes an approach to possible alternative waste management scenarios and attempts to determine the potential cost impact of these scenarios. The general approach taken, that management practices should relate to the waste constituents and

various management alternatives should be evaluated, is appropriate. Nonetheless, API has identified many instances where basic assumptions are in error, overly broad, unsupported by any stated rationale or lead to understated cost impacts. Several of these general issues are identified below while more specific line-by-line comments are included in Attachment 11 of the API comments.

The report suggests a tiered approach to alternate waste management scenarios based upon the concentration of constituents present in the waste. However, there is no mention of the rationale behind the selection of the particular constituents and concentrations chosen or the analytical tests to be employed in the Intermediate Scenario. In fact, it appears the EPA contractor may have utilized references and existing state regulations inappropriately to arrive at elevated trigger concentrations. Further, the report uses the proposed TCLP regulatory limits as a basis for the RCRA Scenario even though EPA has indicated in a Federal Register notice of May 18, 1987 that it is reconsidering the appropriateness of these levels for waste disposal in surface impoundments. API believes that the TCLP is not an appropriate method for determining the type and concentration of constituents which may be released at oil and gas waste facilities.

The scenarios themselves err in several ways. Impacts on point source discharges of produced water that are clearly excluded under RCRA Subtitle C are included. Compounding this mistake is the arbitrarily low chloride concentration (500ppm) used to limit these discharges. Also, no methodology is shown for estimating the number of Class I or II injection wells that would be required to accomodate the volume of produced water previously discharged. Finally, the on-site landspreading of drilling mud pit contents during closure is completely overlooked in the scenarios. This is an important and environmentally sound method of on-site waste management that should be included. In fact, it appears to API that the metals concentrations used as "trigger limits" in the "Intermediate Scenario" were taken from a Louisiana rule that is intended to be applied to landspreading.

The report properly recognizes that existing wells cannot be converted to Class I injection wells, but has made an overly broad generalization in assuming that all additional Class II wells would be conversions of production wells. Engineering difficulties and reservoir considerations will require new Class II wells to be drilled.

No mention is made as to the report's intent regarding injection wells used in enhanced oil recovery projects. API believes that these wells are not appropriate for inclusion in the study since fluids injected for enhanced recovery are not waste within the definition of RCRA and, therefore, cannot be regulated as such. Those injected fluids are not discarded as wastes, but are an integral part of the production process itself.

In developing the costs associated with the alternative practices, the Agency has attempted to adapt models that have not been peer

reviewed and were designed to be used with waste practices from other industries. In addition, the report employs an inappropriate discount rate of 8% and has used inaccurate assumptions to derive cost/barrel unit costs that will lead to significant underestimation of costs. Also, no explanation is given to the manner in which waste volumes will be allocated among the various alternative practices.

In trying to project the subsequent economic implications of each scenario, the report fails to adequately consider several other factors. These include the severe lack of commercial waste disposal capacity that would result, the tremendous transporation costs that will be incurred due to the lack of commercial waste disposal sites and the remote locations of many of the industry's operations, and the loss of performance and increased drilling costs associated with substituting "less toxic materials", such as mineral oil in drilling fluids.

CHAPTER 6 -- Economic Impact of Alternative Waste Management Practices for the Onshore Oil and Gas Industry

Chapter 6 is incomplete and does not address the economic impact of E&P waste regulation on the oil and gas industry. Instead, it specifies 21 "model projects" which purport to represent the economic costs and profitability of drilling and producing hypothetical wells and develops an assessment of their rate of returns with and without additional RCRA regulatory costs. The basic problem with the approach is that the diverse U S oil and gas industry cannot be adequately characterized by 21 model wells (11 owned by majors and 10 owned by independents) located across EPA's 9 geographic regions. The key issue of how the model would represent industry's over 800,000 existing producing wells and their associated 168,000 injection wells and more than 70,000 new wells drilled each year is not even addressed. The model is also flawed in its selection of producing rates and production decline rates which will understate the impact of additional costs. Attachment No. 12 contains further detailed comments.

The approach also does not recognize problems in using rate of return on a well by well basis as the sole indicator of the impact on industry of increased costs due to additional regulation. A reduced rate of return for a well means more than if it can absorb additional investment for regulatory compliance. It also demonstrates that the overall level of industry investment and number of successful projects will both decrease. Attachment 12 describes the type of economic analysis that can quantify these impacts. Furthermore, the analysis does not separate or quantify different impacts on drilling and production activities in relation to today's $18-19 per barrel crude prices (the model uses $25-26 per barrel crude oil prices). This will greatly understate the impact of additional regulations on the E&P industry.

The approach is also deficient in not addressing the impacts of additional regulation outside the oil and gas industry. The Congressional mandate to EPA does not limit the economic analysis to impacts on oil and gas producers. By restricting the scope of its economic analysis, EPA's contractor fails to recognize the large impacts of additional regulatory costs on individuals and state and the federal governments in lost taxes, royalties and other income as well as impacts on the economies of non-oil and gas producing states. Other issues such as translating the loss of producing capacity on U S import levels, balance of payments and national defense requirements are also not addressed in EPA's methodology. These deficiencies will result in an inadequate assessment of economic impacts in EPA's Report to Congress.

CHAPTER 7 -- Summary of State and Federal Regulations

API did not receive Chapter 7 until May 27, 1987 and, consequently, has not had an opportunity to review in detail this voluminous Chapter. However, based upon API's preliminary review, it is clear that there are a number of significant errors and omissions. API will submit more detailed comments when time permits. Since the status of current state regulations is an extremely important part of any regulatory decision, API urges EPA to give serious consideration to API comments that will be presented in the very near future.

COMMENTS WITH RESPECT TO
THE DAMAGE CASE SUMMARIES PREPARED BY
THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
FOR THE STATES OF
OHIO, PENNSYLVANIA AND WEST VIRGINIA
IN CONNECTION WITH
<u>ITS REVIEW OF OIL AND GAS WASTE PURSUANT TO RCRA §8002</u>

ON BEHALF OF THE

INDEPENDENT OIL AND GAS ASSOCIATION OF NEW YORK
INDEPENDENT OIL AND GAS ASSOCIATION OF WEST VIRGINIA
KENTUCKY OIL AND GAS ASSOCIATION
OHIO OIL AND GAS ASSOCIATION
PENNSYLVANIA NATURAL GAS ASSOCIATES
PENNSYLVANIA OIL AND GAS ASSOCIATION
TENNESSEE OIL AND GAS ASSOCIATION
VIRGINIA OIL AND GAS ASSOCIATION
and the
WEST VIRGINIA OIL AND NATURAL GAS ASSOCIATION

SUBMITTED BY:

ROBINSON & McELWEE

David M. Flannery

600 United Center
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Charleston, West Virginia 25326
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June 11, 1987

COMMENTS WITH RESPECT TO
THE DAMAGE CASE SUMMARIES PREPARED BY
THE UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
FOR THE STATES OF
OHIO, PENNSYLVANIA AND WEST VIRGINIA
IN CONNECTION WITH
ITS REVIEW OF OIL AND GAS WASTE PURSUANT TO RCRA §8002

In connection with its study of oil and gas wastes pursuant to RCRA §8002(m), EPA, through its contractor Versar, has identified damage cases that it believes to be relevant. This document will offer detailed comment on the summaries of those damage cases prepared by Versar and offer conclusions which we believe are appropriate on the basis of this analysis.

At the outset, we note that RCRA §8002(m) uses the following language to describe the scope of the damage case review which should be conducted:

> (D) documented cases which prove or have caused danger to human health and the environment from surface runoff or leachate;

As is stated elsewhere in RCRA §8002(m), the overall thrust of the report is to study "the adverse effects, if any, of drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil or natural gas . . . on human health and the environment." Our review of the damage cases will, therefore, be conducted in light of this statutory mandate.

I. OHIO.

Damage case summaries have been prepared for a total of 52 cases. Originally, 44 of the cases were provided but an

additional eight cases were later obtained by us from the regional offices of the Ohio Department of Natural Resources.

A summary of these cases is contained in Exhibit A and our detailed comments on each of the 52 cases are contained in Exhibit B.

Our review of these cases reveals two principal conclusions. First, 11 of the cases should not be given further consideration as part of the RCRA §8002(m) study because they are not within the scope of the mandate established by Congress. Second, the remaining 41 cases involve situations that are adequately regulated by current industry practices and by statutes, regulations, permits and policies of state and federal agencies.

1. <u>Eleven Cases Should Be Deleted From Further Consideration.</u>

The eleven cases which do not meet the congressional mandate for relevancy to this study are as follows:

a. OH01 does not involve the State of Ohio at all. This case arises out of West Virginia where the operator involved was subjected to criminal sanctions for an unauthorized stream discharge.

b. OH13 and OH22 are related to erosion from an oil and gas operation and do not involve waste disposal practices of the industry. Erosion control practices are subject to extensive regulation at the state level; however, since erosion control practices are not within the scope of this study, they should not be given further consideration.

c. OH18, OH19, OH40, OH41, and OH51 are cases in which the documentation does not establish a causal connection between environmental damage and the exploration, development or production of crude oil or natural gas. Accordingly, these cases should not be given further consideration.

d. OH 36 and OH43 are cases which relate to disposal wells which are not involved with the exploration, development or production of crude oil or natural gas. The sole purpose of the wells involved is the disposal of wastes and, accordingly, damage cases resulting from the operation of these wells should not be given further consideration in connection with this study.

e. OH52 is a duplicate of OH39 and should not be given independent consideration.

2. The Remaining 41 Cases Involve Damage From Operations That Are Subject to Adequate Regulation.

Our review of the remaining 41 cases indicates that they can be categorized as follows for purposes of assessing the applicability of existing regulatory requirements:

1. Discharges of waste onto the ground (OH02, OH03, OH04, OH08, OH10, OH11, OH12, OH21, OH23, OH24, OH25, OH26, OH27, OH28, OH29, OH32, OH33 and OH34) in violation of the following requirements:

   - ORC §1509.22 - Improper Disposal of Brine.
   - OAC §1501:9-1-07 - Contamination or Pollution of Land or Water.
   - OAC §1501:9-3-08(A) - Liquid Tight Pits; and

2. Discharge of waste to a surface stream (OH05, OH07, OH31 and OH48) in violation of the following provisions:

   - ORC §1509.22 - Improper Disposal of Brine.
   - ORC §6111.04 - No Discharge Without a Permit.
   - OAC §3745-33 - No Discharge Without an NPDES Permit.
   - OAC §1501-9-1-07 - No Contamination or Pollution of Water on the Surface or Subsurface.
   - OAC §1501-9-3-08 - Liquid Tight Pits.

3. Leachate from brine pits (OH09, OH14, OH15, OH16, OH20, OH35, OH42, and OH49) in violation of:

- ORC §1509.22 - Improper Disposal of Brine.

- OAC §1501-9-1-07 - No Contamination or Pollution of Water on the Surface or in the Subsurface.

- OAC §1501-9-3-08 - Liquid Tight Pits.

4. Leachate or overflow of drilling pits (OH06, OH30, OH37, OH39, OH44, OH46, OH47 and OH50) in violation of:

- ORC §1509.22 - Improper Disposal of Brine.

- OAC §1501-9-3-09 - Liquid Tight Pits.

5. Unauthorized annular disposal (OH17 and OH38) in violation of:

- ORC §1509.22 - Improper Disposal of Brine.

- OAC §1501-9-3-11 - Annular Disposal Approval.

6. Illegal dumping of wastes (OH45) in violation of:
   - ORC §1509.22 - Improper Disposal of Brine.

Nearly all of these 41 cases resulted in the issuance of notices of violation or of directives for remedial action.

II. PENNSYLVANIA.

EPA has four damage cases summaries with respect to Pennsylvania. Our detailed comments on those summaries are contained in Exhibit C. Of these cases, two relate to specific oil and gas well operations while the other two relate to more

general environmental concerns relative to older oil and gas well practices in the Northwestern part of the state.

Based upon our review of these cases, it is apparent that adequate regulatory authority exists at both the state and federal level to respond to the fact situations which these cases raise. The specific categories involved are as follows:

1. Stream discharge without a permit (PA01 and PA08) in violation of:

   - Clean Streams Act.
   - Fish and Boat Code.

2. Release of oil (PA02 and PA08) which invokes the following clean-up remedy:

   - Federal Clean Water Act §311.

III. WEST VIRGINIA.

EPA has identified 22 damage cases arising out of West Virginia. Our detailed comments on those summaries are contained in Exhibit D. As with Ohio, these cases fall into two categories. First, eight of the cases do not meet the congressional mandate for damage cases to be taken into account in this study and should be deleted. Second, the remaining 14 cases indicate that the fact situations involved are adequately regulated under state and federal authority.

1. Eight Cases Should Be Deleted From Further Consideration.

The eight cases which do not meet the congressional mandate for relevancy to this study are as follows:

a. WV02 is a case of environmental damage related to the surface mining of coal and is unquestionably not related to oil and gas operations.

b. WV08 and WV14 are cases where there is no established causal connection between the damage case involved and the exploration, development or production of crude oil or natural gas.

c. WV11, WV21, WV22 and WV35 are cases involving erosion. Even though erosion and sediment control practices are carefully regulated in West Virginia pursuant to W.Va. Code §22B-1-6(d), erosion is not the disposal of drilling fluids, produced waters or other wastes associated with the exploration, development or production of crude oil or natural gas and should, therefore, not be given further consideration in connection with this study.

d. WV18 is a case involving a landowner intentionally using a pit for purposes of supplying water for his domestic cattle. This case clearly is not a case representative of waste disposal practices of the industry and should not be given further consideration in connection with this study.

2. The Remaining 14 Cases Involve Damage From Operations That Are Subject to Adequate Regulation.

Of the remaining 14 damage cases identified, it is apparent that those cases can be categorized as follows for purposes of examining the adequacy of existing state and federal regulatory programs to prevent or mitigate environmental damage resulting from the activities involved:

1. Stream discharge of wastes (WV07, WV09, WV12, WV15, WV16, WV19, WV20, WV26, WV31 and WV32) which is prohibited as follows:

- *W.Va. Code* §20-5A-19 - Pollution Prohibited.

- *W.Va. Code* §20-5A-19 - Payment for Loss of Aquatic Life.

- *W.Va. Code* §22B-1-7 - No Stream Discharge Without Permit.

- General NPDES Permit No. WV0073343 - No Stream Discharge.

2. Temporary vegetation stress (WV13) regulated by:

   - General NPDES Permit No. WV0073343 - Land Application Requirements.

3. Water well contamination (WV01 and WV17) prohibited by:

   - *W.Va. Code* §20-5A-19 - Pollution Prohibited.

   - *W.Va. Code* §22B-1-7 - No Discharge to Ground Water Without a Permit.

   - Administrative Regulations, Chapter 22-4, Series V, Section 9.02 - No Discharge to Ground or Surface Water.

4. Overflow of drilling pits onto ground (WV24) in violation of:

   - General NPDES Permit No. WV0073343 - Pits Must Prevent Overflow.

   - Administrative Regulations, Chapter 22-4, Series V, Section 23.04 - Drilling Pits Shall Prevent Overflow.

Of these 14 cases, 10 clearly resulted in criminal charges being filed against the operator. Criminal charges may also have been filed in other cases but the determination is not sufficiently complete to reach that conclusion. In one case (WV13), the agency responded to that situation by significantly tightening the general permit requirements for land application. In another case (WV17), the state responded to that situation by

revising its surface water casing requirements to take account of a newly discovered drinking water source.

IV. CONCLUSION.

This review makes it clear that a number of the damage cases that have been identified by EPA clearly do not meet the congressional mandate for analysis in connection with RCRA §8002(m).

While there are several cases in which environmental damage has been identified to have been caused by oil and gas operations, it is apparent that adequate regulations are in place by which both the state and federal government can regulate these activities. The damage cases involved not only reveal that there is adequate authority to regulate these activities but also that state and federal agencies have vigorously enforced these authorities to prevent or mitigate any environmental damage that may have resulted in these operations. Moreover, the small number of cases involved relative to the number of existing and new wells involved indicates a high level of compliance.

Respectfully submitted this 11th day of June, 1987.

INDEPENDENT OIL AND GAS ASSOCIATION OF NEW YORK
INDEPENDENT OIL AND GAS ASSOCIATION OF WEST VIRGINIA
KENTUCKY OIL AND GAS ASSOCIATION
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EXHIBIT A

SUMMARY OF DAMAGE CASES CITED BY EPA WITH RESPECT TO

OHIO

PENNSYLVANIA

and

WEST VIRGINIA

SUMMARY OF DAMAGE CASES CITED BY EPA

OHIO

	Description	Conclusions
OH01	stream discharge of frac fluids (criminal charges)	delete - not an Ohio case
OH02	produced water onto ground	adequate state enforcement
OH03	produced water onto ground	adequate state enforcement
OH04	produced water onto ground	adequate state enforcement
OH05	produced water to stream	adequate state enforcement
OH06	leachate from drill cuttings	adequate state enforcement
OH07	brine discharge to stream	adequate state enforcement
OH08	brine discharge onto ground	adequate state enforcement
OH09	leachate from brine pit	adequate state enforcement
OH10	leaking brine tank	adequate state enforcement
OH11	brine discharge onto ground	adequate state enforcement
OH12	brine discharge onto ground	adequate state enforcement
OH13	erosion	delete - not waste disposal
OH14	open brine pit	adequate state enforcement
OH15	brine contamination of water well	adequate state enforcement
OH16	brine contamination of water well	adequate state enforcement
OH17	illegal annular disposal	adequate state enforcement
OH18	contamination of water well	delete - no causal connection
OH19	brine contamination of water well	delete - no causal connection
OH20	improper brine disposal	adequate state enforcement
OH21	brine discharge onto ground	adequate state enforcement
OH22	erosion	delete - not waste disposal
OH23	brine contamination of water and soil	adequate state enforcement
OH24	leaky brine tank and pipe	adequate state enforcement
OH25	leaky brine tank	adequate state enforcement
OH26	leaky brine tank	adequate state enforcement
OH27	leaky brine tank	adequate state enforcement
OH28	leaky brine pipe	adequate state enforcement
OH29	leaky brine tank	adequate state enforcement
OH30	drilling pit overflowed	adequate state enforcement
OH31	brine discharge to stream	adequate state enforcement
OH32	leaky brine tank	adequate state enforcement

OH33	leaky brine pipeline	adequate state enforcement
OH34	leaky brine piepline	adequate state enforcement
OH35	brine contamination of water well	adequate state enforcement
OH36	soil contamination from commercial disposal	delete - not oil and gas
OH37	drilling pit, water well contamination	adequate state enforcement
OH38	improper annular disposal	adequate state enforcement
OH39	drilling pit, ground water contamination	adequate state enforcement
OH40	water well contamination	delete - no causal connection
OH41	water well contamination	delete - no causal connection
OH42	brine contamination of water well	adequate state enforcement
OH43	spring contamination from commercial disposal	delete - not oil and gas
OH44	drilling pit, water well contamination	adequate state enforcement
OH45	illegal dumping	adequate state enforcement
OH46	drilling pit, water well contamination	adequate state enforcement
OH47	drilling pit, water well contamination	adequate state enforcement
OH48	stream discharge of brine	adequate state enforcement
OH49	brine contamination of water well	adequate state enforcement
OH50	drilling pit, water well contamination	adequate state enforcement
OH51	stream contamination	delete - no causal connection
OH52	N/A	delete - same as OH39

PENNSYLVANIA

	Description	Conclusions
PA01	various stream discharges	adequate state enforcement
PA02	survey of five streams	adequate state enforcement
PA08	contamination of water supply	adequate state enforcement
PA09	four county cleanup	adequate state enforcement

WEST VIRGINIA

	Description	Conclusions
WV01	water well contamination	adequate state enforcement
WV02	strip mining contamination	delete - not oil and gas
WV07	brine discharge to stream	adequate state enforcement (criminal)
WV08	dead cows around drilling pit	delete - no causal connection
WV09	frac fluid discharge to stream	adequate state enforcement (criminal)
WV11	erosion	delete - not waste disposal
WV12	brine discharge to stream	adequate state enforcement (criminal)
WV13	temporary vegetation stress	adequate state enforcement (revised permit)
WV14	unproven casing leak	delete - no causal connection
WV15	drilling pit stream discharge	adequate state enforcement (criminal)
WV16	frac fluid discharge to stream	adequate state enforcement (criminal)
WV17	water well contamination	adequate state enforcement (revised casing requirements)
WV18	intentional use of pit for cattle water	delete - not waste disposal
WV19	discharge of drilling waste to stream	adequate state enforcement
WV20	discharge of drilling water to stream	adequate state enforcement (criminal)
WV21	erosion	delete - not waste disposal
WV23	erosion (criminal charges)	delete - not waste disposal
WV24	overflow of drilling pit onto ground	adequate state enforcement (criminal)
WV26	discharge of drilling waste to stream	adequate state enforcement (criminal)
WV31	discharge of drilling waste to stream	adequate state enforcement (criminal)
WV32	discharge of drilling waste to stream	adequate state enforcement (criminal)
WV35	erosion	delete - not waste disposal

File Ref# WV 17 *State* WV

yes *Nearest City or Town* Ripley

Region 2 *County/Parish* Jackson

Proof Category *Administrative* 1 *Legal* *Scientific/technica* 1 *0 = no 1 = yes*

Description of Operation

Production Area Appalachian Basin *(basin, region, etc.)*

Production Type Gas *(oil, gas, injection well, etc.)*

Production Category Development *(exploration, development, production, or other)*

Description of Operation

In 1982 Kaiser Gas Co. drilled a gas well on the property of Mr. James Parsons. The well was fractured using a typical fracturing fluid or gel. The residual fracturing fluid migrated into Mr. Parson's water well, drilled to a depth of 416ft. (The gas well is located less than 1000 ft. from the water well.) By 1984, the water well was unfit for domestic use and an alternate source of water had to be found.

Fresh water casing was set 30' below the lowest known fresh water zone; however neither the operator nor the agency knew Mr. Parson was taking water from such a deep well. Current practices have been revised to account for this situation.. Mr Parsons has not returned to using the well as a water source.

Description of Waste and Damage

Pathway of Contamination *(yes/no)* *Ground Water* yes *Surf. Water* *Soil*

Damage Source gas well *(reserve, holding or emergency pit; tank, well, battery; spill; injection well; blowdown, etc.)*

Areal Extent

Waste Stream fracturing fluid or gel *(mud, brine, produced water, workover fluid, frac fluid, etc.)*

Waste Analysis Well water was analyzed and found to contain high levels of fluoride, sodium, iron, manganese. The water had a hydrocarbon odor indicating the presence of gas. Dark and light gelatinous material (fracturing fluid), was found along with white fibers. *(describe nature of available analysis, cite key numbers if available)*

Waste Volume Released NA *(barrels, gallons, etc.)*

3/4/87&

Areal Extent	NA	*(acres)*
Date of Release	1982	*(release may be ongoing, recently reported, etc.)*
Duration	Approximately 12 hours	*(comment as needed)*

Affected Biota (yes/no) *Fauna* [ ] *Flora* [ ] *Human Health* [yes]

Damage Description When fracturing the Kaiser gas well on Mr. James Parson's property, fractures were created allowing migration of fracture fluid from the gas well to Mr. Parson's water well. This fracture fluid, along with natural gas was present in Mr. Parson's water rendering it unusable. The contamination has since passed through the water well but is still contained in the groundwater.

This is an area where water problems have been known to occur independent of oil and gas operations. Litigation brought in connection with this case was without any admission of liability.

Violations State Regs. [0] *(0=No 1=Yes) at time of damage*

Compliance Issues No apparent compliance issues - no laws dictating proximity of oil and gas wells to water wells - no maximum pressure dictated for fracturing oil and gas wells.

NOT TRUE.
State law requires a fresh water casing to be set 30' below the lowest fresh water zone. This case caused the state agency to become aware of a lower fresh water zone than had previously been known and future requirements were changed accordingly.

Documentation Three lab reports containing analusis of water well. Letter from J. E. Rosencrance, Environmental Health Services Lab, to P. E. Merritt, Sanitarian, Jackson County. Letter from P. R. Merritt to J. E. Rosencrance requesting analysis. Letter from M. W. Lewis, Office of Oil and Gas to James Parsons stating state cannot help in recovering expenses - must file civil suit. Water well inspection report - complaint. Sample report forms.
Letter to Flannery from Strat (WVDOE) dated May 29, 1987.

Comment State statute requires casing to protect fresh water zones. In this case the agency was not aware of this fresh water zone. Upon discovery appropriate revision was made to casing requirements for drilling in this area. Whether Kengas actually caused contamination of Mr. Parson's well is a matter which is not resolved.

3/4/87&

STATE OF WEST VIRGINIA
DEPARTMENT OF ENERGY
322 70th STREET, SOUTHEAST
CHARLESTON, WEST VIRGINIA 25304
TELEPHONE 348-3741

ARCH A. MOORE, JR.
GOVERNOR

KENNETH R. FAERBER
COMMISSIONER

DOE/DO&G-0356

May 29, 1987

Mr. Dave Flannery
Robinson and McElwee
600 Kanawha Banking & Trust Center
Charleston, West Virginia 25301

Re: Letter of May 25, 1987

Dear Dave:

This is in response to your request for further information on West Virginia damage case number WV 17. I have enclosed copies of our file in this case.

I would like to point out that WV Code 22B-1-20 requires an operator to cement a string of casing 30 feet below all fresh water zones. At the time the permit was issued concerning this well the Division had no knowledge that the Pittsburg sand was a fresh water source. This is because in certain areas oil and gas is produced from the Pittsburg. With this case however, the division discovered the problem and took the following steps to remedy the situation: 1) We had a geologist map the Pittsburg sand in the Roane and Jackson county area so that our permits group and enforcement group knew where that sand could be found. 2) We required every well drilled in the area to have casing cemented up over the Pittsburg sand. This in itself added eight per cent to the total cost of drilling a well in the area.

I hope this helps claifiy the situation and if you have any further questions feel free to contact me.

Sincerely,

Ted M. Streit
Deputy Director
Inspection and Enforcement
Divsion of Oil and Gas

TMS:las

Encls. (as stated)

ROLL	FRAME	DOCID	DOC DATE	TITLE
OGRA 018				AND SAMPLING QUALITY ASSURANCE/QUALITY CONTROL PLAN
	1787	F-88-OGRA-S0555	860820	EXXON - EPA MEETING LABARGE FACILITY WYOMING
	2457	F-88-OGRA-S0556	860822	LETTER TO LEE THOMAS REGARDING THE METHODOLOGY FOR FIELD SAMPLING
	2459	F-88-OGRA-S0557	860905	LETTER TO SUSAN DENAGY REGARDING OIL AND GAS EXPLORATION DEVELOPMENT AND PRODUCTION FIELD SAMPLING PROGRAM
	2461	F-88-OGRA-S0558	860917	OVERVIEW OF MEETING BETWEEN IOCC AND EPA 9-10-86
	2464	F-88-OGRA-S0559	861021	LETTER REGARDING WASTES GENERATED ON OFFSHORE OIL AND GAS RIGS AND PLATFORMS WITHIN TEXAS
	2466	F-88-OGRA-S0560	851211	LETTER TO ELLIOTT LAWS AND BARBARA PACE REGARDING ALASKA CENTER FOR THE ENVIRONMENT V. EPA
	2468-2470 INDEX			
OGRA 019	0002	F-88-OGRA-S0561	860425	DRAFT REPORT ON ROUND-ROBIN EVALUATION FOR SELECTED ELEMENTS AND ANIONIC SPECIES FROM TCLP AND EP EXTRATIONS
	0195	F-88-OGRA-S0562	860310	BACKGROUND DOCUMENT RCRA SUBTITLE C - HAZARDOUS WASTE MANAGMENT SYSTEM SECTION 3001 IDENTIFICATION AND LISTING OF HAZARDOUS WASTE TOXICITY CHARACTERISTIC LEACHING PROCEDURE (TCLP)
	0273	F-88-OGRA-S0563	860215	SINGLE LABORATORY TESTING OF THE TOXICITY CHARACTERISTIC LEACHING PROCEDURE (TCLP) USING CONVENTIONAL APPARATUS
	0360	F-88-OGRA-S0564	860702	PRECISION EVALUATION OF THE TOXICITY CHARACTERISTIC LEACHING PROCEDURE (TCLP) FOR VOLATILE CONTAMINANTS
	0383	F-88-OGRA-S0565	860714	DATA; A HEARING CONCERNING PROPOSED RULE-TOXICITY CHARACTERISTIC
	0599	F-88-OGRA-S0566	860915	COLLABORATIVE STUDY OF THE TOXICITY CHARACTERISTICS LEACHING PROCEDURE (TXLP)
	0649	F-88-OGRA-S0567	860812	COMMENTS OF THE ENVIRONMENTAL DEFENSE FUND ON THE JUNE 13 1986 PROPOSED TOXICITY CHARACTERISTIC LEACHING PROCEDURE
	0703	F-88-OGRA-S0568	860812	LETTER REGARDING COMMENTS OF THE AMERICAN PETROLEUM INSTITUTE AND ITS APPROXIMATELY 230 MEMBER COMPANIES CONCERNING EPA'S PROPOSED TOXICITY CHARACTERISTIC LEACHING PROCEDURE (TCLP)
	0753	F-88-OGRA-S0569	990909	HAZARDOUS WASTE MANAGEMENT SYSTEM: IDENTIFICATION AND LISTING OF HAZARDOUS WASTES DOCKET NO. F-86-TC-FFFFF - COMMENTS OF THE RAILROAD COMMISSION OF TEXAS
	0756	F-88-OGRA-S0570	860127	STATUS OF UIC PROGRAMS
	0760	F-88-OGRA-S0571	860206	INTEROFFICE CORRESPONDENCE TO ALL HAZARDOUS WASTE DIVISION PERSONNEL REGARDING STATUS OF OFF-SHORE OIL

notice, it is due to the quality of the document being filmed

OGRA 019

ROLL	FRAME	DOCID............	DOC DATE..	TITLE..
OGRA 014				PLATFORMS
	0762	F-88-OGRA-S0572	X 860305	AGENDA - API-EPA MEETING RCRA 8002 (m) DRILLING MUD STUDY ROOM 2126-EPA HEADQUARTERS
	0766	F-88-OGRA-S0573	860414	LETTER REGARDING A MEETING CONCERNING THE VIEWPOINT OF THE INDEPENDENT OIL AND GAS ASSOCIATION OF WEST VIRGINIA AND THE WEST VIRGINIA OIL AND NATURAL GAS ASSOCIATION REGARDING THE AGENCY'S STUDY OF OIL AND GAS WASTES UNDER 8002 OF RCRA
		"surface owners rights [illegible] were not seriously considered"		
	0840	F-88-OGRA-S0574	860502	LIST OF ATTENDANCE OF A MEETING CONCERNING OIL AND GAS
	0842	F-88-OGRA-S0575	860624	LETTER REGARDING A MEETING WITH PATRICK PESACRETA SUSAN DENAGY AND JOHN JOHNSTON TO DISCUSS EPA'S CURRENT REVIEW OF THE OIL AND GAS INDUSTRY BOTH FROM THE STANDPOINT OF RCRA AND THE CLEAN WATER ACT
	0890	F-88-OGRA-S0576	860624	CORRESPONDENCE REGARDING DRILLING MUDS PRODUCED WATER AND ASSOCIATED WASTES ARE CURRENTLY EXEMPTED FROM HAZARDOUS WASTE REGULATIONS
	0897	F-88-OGRA-S0577	860703	LETTER REGARDING IOCC PARTICIPATION IN THE REVIEW OF THE ONGOING EPA STUDY OF THE OIL AND GAS INDUSTRY HAZARDOUS WASTE EXEMPTIONS
	0900	F-88-OGRA-S0578	860703	MEMORANDUM REGARDING TELEPHONE CONFIRMATION-JULY 7 1986 CONCERNING INCREASED INDUSTRY CONTACTS FOR THE OIL AND WASTE REGULATORY DETERMINATION WORK GROUP
	0902	F-88-OGRA-S0579	860722	LETTER REGARDING RECENT ENVIRONMENTAL PROTECTION AGENCY ADMINISTRATIVE ACTIONS DIRECTED AGAINST THE GEOTHERMAL INC. AND IT CORPORATION NON-HAZARDOUS WASTE FACILITIES LOCATED IN LAKE COUNTY CALIFORNIA
	0907	F-88-OGRA-S0580	X 860703	MEETING AGENDA JULY 23 1986; U.S. EPA AND APPALACHIAN OIL AND GAS PRODUCERS REGARDING EPA'S RCRA/CWA STUDY OF OIL AND GAS INDUSTRY
	0911	F-88-OGRA-S0581	870415	A PILOT SURVEY OF STATE MECHANICAL INTEGRITY TESTING (MIT)-NEW MEXICO
	1003	F-88-OGRA-S0582	870408	EXECUTIVE SUMMARY; THE ECONOMIC IMPACT OF COMPLIANCE T90 RCRA ON THE TEXAS OIL AND GAS INDUSTRY
	1092	F-88-OGRA-S0583	870408	REVIEW OF COMMENTS SUBMITTED TO THE OIL AND GAS EXTRACTION WASTE DOCKET
	1221	F-88-OGRA-S0584	870409	MEMORANDUM TO ROBERT HALL REGARDING COMMENTS ON DRAFT SUMMARIES OF OIL AND GAS REGULATIONS
	1224	F-88-OGRA-S0585	870414	LETTER REGARDING U.S. EPA REPORT TO CONGRESS ON WASTES RELATED TO THE OIL AND GAS INDUSTRY
	1225	F-88-OGRA-S0586	870415	LETTER REGARDING A REPORT ON ARCTIC OIL

notice, it is due to the quality of the document being filmed

OGRA C19

ROLL FRAME	DOCID............	DOC DATE..	TITLE....................................
			AND GAS EXPLORATION AND PRODUCTION WASTES
1272	F-88-OGRA-S0587	870415	API RCRA EXEMPTION STUDY TASK I PRODUCTION WASTE STUDY
1320	F-88-OGRA-S0588	870417	LETTER REGARDING THE EPA'S UPCOMING REPORT TO CONGRESS ON WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY
1322	F-88-OGRA-S0589	870423	LETTER REGARDING ARCTIC PRODUCTION WASTE DATA RESERVE PIT WASTE CHARACTERIZATION
1325	F-88-OGRA-S0590	870130	REPORT ON SAPC PRUDHOE BAY PRODUCED WATER AND RESERVE PIT MUD AND WATER CHARACTERISTICS TECHNICAL SERVICE RESPONSE NO. 5611
1332	F-88-OGRA-S0591	870430	SUMMARY OF COMMENTS OF THE AMERICAN PETROLEUM INSTITUTE ON THE U.S. EPA'S "WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY" INTERIM REPORT
1344	F-88-OGRA-S0592	870415	EPA RESULTS; SUMMER/86 SAMPLING AND ANALYSIS OF OIL AND GAS EXPLORATION DEVELOPMENT AND PRODUCTION WASTES
1719	F-88-OGRA-S0593	990909	COMMENTS BY THE TEXAS RAILROAD COMMISSION INTERIM REPORT CHAPTER II: CURRENT AND ALTERNATIVE PRACTICES
1730	F-88-OGRA-S0594	990909	COMMENTS BY THE TEXAS RAILROAD COMMISSION INTERIM REPORT CHAPTER II: CURRENT AND ALTERNATIVE PRACTICES
1746	F-88-OGRA-S0595	870615	LETTER REGARDING COMMENTS ON INTERIM REPORT OF WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY
1858	F-88-OGRA-S0596	870615	LETTER REGARDING "WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY " CONTRACTORS' INTERIM REPORT DATED APRIL 30 1987
1892	F-88-OGRA-S0597	870615	COMMENTS REGARDING THE APRIL 30 1987 INTERIM REPORT OF THE U.S. EPA WITH RESPECT TO WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY
1952	F-88-OGRA-S0598	870615	LETTER REGARDING SUBMITTING COMMENTS ON THE INTERIM REPORT OF THE ENVIRONMENTAL PROTECTION AGENCY "WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY
1957	F-88-OGRA-S0599	870615	LETTER REGARDING COMMENTS ON THE APRIL

OGRA 019

OGRA 019

ROLL FRAME	DOCID............	DOC DATE..	TITLE....................................
			30 1987 INTERIM REPORT ON "WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY
1956	F-88-OGRA-S0600	870615	LETTER REGARDING INTERIM REPORT TITLED "WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY
1958	F-88-OGRA-S0601	990909	LETTER REGARDING CONCERNS WITH CHAPTER 3 OIL AND GAS DAMAGE CASES IN THE INTERIM REPORT ON WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY
1979	F-88-OGRA-S0602	870617	LETTER REGARDING COMMENT IN SUPPORT OF THE AMERICAN PETROLEUM INSTITUTE'S RESPONSE TO THE EPA'S APRIL 30 1987 INTERIM REPORT TITLED "WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY"
1980	F-88-OGRA-S0603	870619	LETTER REGARDING COMMENTS ON PART II GEOTHERMAL ENERGY OF THE APRIL 30 1987 1987 INTERIM REPORT ON WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY
1986	F-88-OGRA-S0604	870622	LETTER TO ROBERT W. HALL REGARDING COMPARISON OF FIT WASTES USED IN COLUMN STUDIES TO WASTES FROM 20 SAMPLED SITES
2063	F-88-OGRA-S0605	870626	MEMORANDUM REGARDING MEETING WITH AMERICAN PETROLEUM INSTITUTE
2091	F-88-OGRA-S0606	X 870626	LETTER TO DAN DERKICS REGARDING SEVENTEEN DAMAGE CASES INTERIM REPORT CONTAIN MISLEADING INFORMATION AND INAPPROPRIATE INTERPRETATIONS
2132	F-88-OGRA-S0607	870626	LETTER TO DAN DERKICS REGARDING VERBAL CONCERNS ABOUT MAY 29 COMMENTS ON THE OIL AND GAS AND GEOTHERMAL MINERAL WASTE STUDY
2134	F-88-OGRA-S0608	870629	LETTER TO JOHN CATLIN REGARDING AIR QUALITY ISSUES RELATING TO ALASKA'S NORTH SLOPE
2158	F-88-OGRA-S0609	870515	RESPONSE TO THE EPA INTERIM REPORT DATED APRIL 30 1987 ON WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY
2197	F-88-OGRA-S0610	870515	CITIZEN'S HANDBOOK ON WATER QUALITY STANDARDS
2219	F-88-OGRA-S0611	870505	LETTER TO ROBERT HALL REGARDING COST ESTIMATES USED IN THE STANDARD ECONOMIC

ROLL	FRAME	DOCID	DOC DATE	TITLE
OGRA 019				MODELS
	2227	F-88-OGRA-S0612	870505	LETTER TO ROBERT HALL REGARDING CORRECTIONS ON DRAFT DAMAGE CASES FROM OKLAHOMA FOR EPA'S REPORT TO CONGRESS ON WASTES RELATED TO THE OIL AND GAS INDUSTRY LETTER OF MAY 1 1987
	2228	F-88-OGRA-S0613	990909	CATEGORIZATION OF EPA DAMAGE CASES
	2247	F-88-OGRA-S0614	870522	LETTER TO DAN DERKICS REGARDING TECHNICAL REPORT ON FIELD SAMPLING AND ANALYTICAL RESULTS
	2249	F-88-OGRA-S0615	870527	ARCTIC NATIONAL WILDLIFE REFUGE: UNANSWERED QUESTIONS; PUBLIC FORUM
	2261	F-88-OGRA-S0616	870529	LETTER TO DAVE FLANNERY REGARDING INFORMATION ON WEST VIRGINIA DAMAGE CASE NUMBER WV 17
	2262	F-88-OGRA-S0617	870529	LETTER REGARDING INTERIM REPORT ON WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY
	2264-2268 INDEX			
		F-88-OGRA-S0618	870612	LETTER REGARDING ORAL COMMENTS ON THE EPA TECHNICAL REPORT: WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY
		F-88-OGRA-S0619	870604	API-EPA MEETING DRILLING FLUID VOLUME ESTIMATE
		F-88-OGRA-S0620	870605	LETTER REGARDING INTERIM REPORT APRIL 30 1987- WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY
		F-88-OGRA-S0621	990909	LETTER REGARDING SAMPLING SURVEY CONDUCTED BY THE HEALTH DEPARTMENT SINCE RELATED TO OIL AND GAS OPERATIONS
		F-88-OGRA-S0622	870608	LETTER REGARDING INFORMATION ON FIELD ENFORCEMENT PERSONNEL AND THEIR DUTIES ALSO ORGANIZATIONAL CHART OF THE RAILROAD COMMISSION OF TEXAS OIL AND GAS DIVISION
		F-88-OGRA-S0623	870608	LETTER REGARDING DAMAGE CASES "TECHNICAL REPORT: WASTES FROM THE EXPLORATION DEVELOPMENT AND PRODUCTION OF CRUDE OIL NATURAL GAS AND GEOTHERMAL ENERGY AN INTERIM REPORT ON METHODOLOGY FOR DATA COLLECTION AND ANALYSIS
		F-88-OGRA-S0624	870609	LETTER REGARDING STATEMENTS FROM THE KANSAS RESPONSE TO EPA'S SUMMARY OF "DAMAGE CASES" INVOLVING OIL AND GAS OPERATIONS IN KANSAS
		F-88-OGRA-S0625	870610	LETTER REGARDING REMARKS CONCERNING THE "DAMAGE CASES"
		F-88-OGRA-S0626	870611	LETTER REGARDING COMMENTS ON EPA'S INTERIM REPORT TITLED "WASTES FROM THE

E6-RA-50 616

Exhibit B

STATE OF WEST VIRGINIA
DEPARTMENT OF ENERGY
322 70th STREET, SOUTHEAST
CHARLESTON, WEST VIRGINIA 25304
TELEPHONE 348-3741

ARCH A. MOORE, JR.
GOVERNOR

KENNETH R. FAERBER
COMMISSIONER

DOE/DO&G-0356

May 29, 1987

Mr. Dave Flannery
Robinson and McElwee
600 Kanawha Banking & Trust Center
Charleston, West Virginia 25301

Re: Letter of May 25, 1987

Dear Dave:

This is in response to your request for further information on West Virginia damage case number WV 17. I have enclosed copies of our file in this case.

I would like to point out that WV Code 22B-1-20 requires an operator to cement a string of casing 30 feet below all fresh water zones. At the time the permit was issued concerning this well the Division had no knowledge that the Pittsburg sand was a fresh water source. This is because in certain areas oil and gas is produced from the Pittsburg. With this case however, the division discovered the problem and took the following steps to remedy the situation: 1) We had a geologist map the Pittsburg sand in the Roane and Jackson county area so that our permits group and enforcement group knew where that sand could be found. 2) We required every well drilled in the area to have casing cemented up over the Pittsburg sand. This in itself added eight per cent to the total cost of drilling a well in the area.

I hope this helps claifiy the situation and if you have any further questions feel free to contact me.

Sincerely,

Ted M. Streit
Deputy Director
Inspection and Enforcement
Divsion of Oil and Gas

TMS:las

Encls. (as stated)

OG-10

STATE OF WEST VIRGINIA
DEPARTMENT OF MINES
OIL AND GAS DIVISION

WELL RECORD

Permit No. Jac-111

Oil or Gas Well Gas (KIND)

Company United Carbon Company
Address 901 Union Building, Charleston, W.Va.
Farm D.F.Hyre Acres 169.66
Location (waters) Mill Creek
Well No. 1 Elev. 802.5
District Ripley County Jackson
The surface of tract is owned in fee by
Opie F.Hyre et al Address Ripley, W.Va.
Mineral rights are owned by
Opie F.Hyre, et al Address Ripley, W.Va.
Drilling commenced Jan. 22, 1941.
Drilling completed May 13, 1941.
Date shot May 13, 1941. Depth of shot 5113 to 5150
Open Flow /10ths Water in Inch
13/10ths Merc. in 7" O.D. 22# Inch
Volume 5,628,000 Cu. Ft.
Rock Pressure 1890 lbs. 48 hrs.
Oil bbls., 1st 24 hrs.
Fresh water 200 feet 595 feet
Salt water 1520 feet 1790 feet

Casing and Tubing	Used in Drilling	Left in Well	Packers
Size			
16			Kind of Packer
13	500'	00	
10-3/4"	1015'	1015'	Size of
8-5/8"	2115'	2115'	
7" O.D.	5022'	5022'	Depth set
5 3/16			
3			Perf. top
2 Tube		5142'	Perf. bottom
Liners Used			Perf. top
			Perf. bottom

CASING CEMENTED 8-5/8" SIZE 576 No. Ft. 3/26/41 Date
7" O.D. 195' 4/27/41

COAL WAS ENCOUNTERED AT FEET INCHES
FEET INCHES FEET INCHES
FEET INCHES FEET INCHES

Formation	Color	Hard or Soft	Top	Bottom	Oil, Gas or Water	Depth Found	Remarks
Soil			0	17			
Red Rock			17	47			
Blue Slate			47	77			
Red Rock			77	117			
Slate			117	165			
Sand			165	210	Water	200'	
Slate			210	235			
Red Rock			235	255			
Sand			255	275			
Red Rock			275	300			
Sand			300	360			
Red Rock			360	365			
Sand			365	410			
Slate			410	420			
Sand			420	430			
Red Rock			430	530			
Sand			530	545			
Red Rock			545	575			
Sand			575	616	Water	595'	
Slate & shells			616	703			
Sand			703	738			
Slate & shells			738	760			
Sand			760	775			
Bluee Slate			775	800			
Red Rock			800	840			
Slate			840	910			
Sand			910	955			
Slate			955	975			
Red Rock			975	1025			
Sand			1025	1045			
Slate			1045	1065			
Red Rock			1065	1075			
Slate			1075	1231			
Sand			1231	1261			
Slate			1261	1266			
Sand			1266	1284			
Slate			1284	1294			
Sand			1294	1365			
Slate			1365	1390			
Sand			1390	1445			
Slate			1445	1490			

MAY 1941
WEST VIRGINIA
DEPARTMENT OF MINES

(Over)

Formation	Color	Hard or Soft	Top	Bottom	Oil, Gas or Water	Depth Found	Remarks
Sand			1490	1550	Water	1520'	
Slate			1550	1575			
Sand			1575	1595			
Slate			1595	1600			
Sand			1600	1620			
Slate			1620	1630			
Lime Shells			1630	1650			
Slate & Shells			16 53	1700			
Salt Sand			1700	1885	Water	1790'	
Little Lime			1885	1910			
Big Lime			1910	1960			
Injun Sand			1960	1975			
Lime			1975	2010			
Slate			2010	2020			
Sand			2020	2030			
Slate			2030	2040			
Lime			2040	2068			
Slate			2068	2075			
Lime Shalls			2075	2110			
Slate & shells			2110	2470			
Lime Gritty			2470	2500			
Slate & shells			2500	2550			
Slate & shells			2550	2850			
White slate			2850	3580			
Slate & shells			3580	3717			
Brown Shale			3717	3780	Gas	3760'	Show
Slate & Shells			3780	3980			
Brown Shale			3980	4056			
White Slate			4056	4170	Gas	4165'	Show
Brown Shale			4170	4270			
Slate & Shells			4270	4300			
White Slate			4300	4420			
Brown Shale			4420	4445			
Slate			4445	4710			
Brown Shale			4710	4825			
Blue Slate			4825	4912			
Black Shale			4912	5003			
Corniferous Lime			5003	5111			
Oriskany Sand			5111	3171			
Lime			5171	5186			
Sand			5186	5198			
Lime			5198	5200			
Sand			5200	5204			
Lime			5204	5210			
Total Depth				5210			

Hole Filled to 5150' shot With 75 Qts Glycerine from 5113' to 5150'.

Well drilled by-
SWH.Cert, Drilling Contractor

Drillers--
Leslie Sparr
R.P.Pickins

Date May 23, 1941

APPROVED United Carbon Co, Owner

By Tomius Morris Supt. (Title)

FORM OG-8

STATE OF WEST VIRGINIA
DEPARTMENT OF MINES
OIL AND GAS DIVISION

AFFIDAVIT OF PLUGGING AND FILLING WELL

AFFIDAVIT SHOULD BE MADE IN TRIPLICATE. ONE COPY MAILED TO THE DEPARTMENT, ONE COPY TO BE RETAINED BY THE WELL OPERATOR AND THE THIRD COPY (AND EXTRA COPIES IF REQUIRED) SHOULD BE MAILED TO EACH COAL OPERATOR AT THEIR RESPECTIVE ADDRESSES.

.... COAL OPERATOR OR OWNER	United Carbon Company NAME OF WELL OPERATOR
.... ADDRESS	United Carbon Bldg. Charleston, W.Va. COMPLETE ADDRESS
.... COAL OPERATOR OR OWNER	August 22, 1949
	WELL AND LOCATION
.... ADDRESS	Ripley District
.... LEASE OR PROPERTY OWNER	Jackson County
.... ADDRESS	Well No. 1
	D.F.Hyre Farm

STATE INSPECTOR SUPERVISING PLUGGING D.E. Lawson

AFFIDAVIT

STATE OF WEST VIRGINIA,
County of Jackson } ss:

Algie McKinney and Charlie Humphreys being first duly sworn according to law depose and say that they are experienced in the work of plugging and filling oil and gas wells and were employed by Otis Eastern Service, Inc. well operator, and participated in the work of plugging and filling the above well, that said work was commenced on the 28 day of July, 1949, and that the well was plugged and filled in the following manner:

SAND OR ZONE RECORD	FILLING MATERIAL			PLUGS USED	CASING	
FORMATION	CONTENT	FROM	TO	SIZE & KIND	CSG PULLED	CSG LEFT IN
	Pulled 5166' of 2" tubing.					
	Set bridge at 5088' 28' above shot hole and filled to					
	5022' bottom of 7" casing					
	Filled from 5022' to 5012' with cement sealing Oriskany					
	Sand.					
	Cut & pulled 3056'10" of 7" casing.					
	Set bridge at 2165' and filled to 2115' with clay					
	Filled from 2115' to 2105' with cement.					
	Cut and pulled 1542' of 8-5/8" casing.					
	Set bridge at 1542' and filled to 1492' with clay & stone					
	Filled from 1492' to 1482' with cement.					
	Set bridge at 1105' and fill to 1055' with clay & stone					
	Fill from 1055' to 1045' with cement.					
	Pulled 1016'10" of 10-3/4" casing.					
	Set bridge at 620' and dumped 3 sacks cement on bridge					
COAL SEAMS	Filled from 620' to 575' and dumped 3 sacks cement.			DESCRIPTION OF MONUMENT		
(NAME)	Set bridge at 210' and dumped 3 sacks cement on bridge					
(NAME)	Filled from 210' to surface.					
(NAME)	Erected monument as prescribed by law.					
(NAME)						

and that the work of plugging and filling said well was completed on the 18 day of August 18, 1949.

And further deponents saith not. Algie McKinney
Charlie L Humphreys

Sworn to and subscribed before me this 14 day of September, 1949.

James Ryan
Notary Public.

My commission expires:
April 16, 1958

Permit No. Jac-111-P

FORM OG-1

NOTICE OF PROPOSED LOCATION OF OIL AND GAS WELL

(REQUIRED BY SECTION 2, CHAPTER 22, CODE 1931)

WEST VIRGINIA DEPARTMENT OF MINES

OIL AND GAS SECTION

TO THE DEPARTMENT OF MINES,
Charleston, W. Va.

______________________ COAL OPERATOR OR COAL OWNER	UNITED CARBON COMPANY NAME OF WELL OPERATOR
______________________ ADDRESS	BOX 1475, CHARLESTON, W. VA. COMPLETE ADDRESS
______________________ COAL OPERATOR OR COAL OWNER	JUNE 4, 1941 193__
	PROPOSED LOCATION
______________________ ADDRESS	Ripley District
F. F. Starcher, OWNER OF MINERAL RIGHTS	Jackson County
809 Fifth Avenue, Huntington, W. Va. ADDRESS	38° 50 — 81° 35' Well No. 1 - Sv. 955
	~~F. F. Starcher, mineral~~ Farm Eph Stewart, surface

GENTLEMEN:

The undersigned well operator is entitled to drill upon the above named farm or tract of land for oil and gas, having fee title thereto, (or as the case may be) under grant or lease dated December 30, 1941, made by F. F. Starcher, to UNITED CARBON COMPANY, and recorded on the 8th day of January, 1941, in the office of the County Clerk for said County in Book 53, page 431.

The enclosed plat was prepared by a competent engineer and shows the proposed location of a well to be drilled for oil and gas by the undersigned well operator on the farm and in the Magisterial District and County above named, determined by survey and courses and distances from two permanent points, or land marks.

The undersigned well operator is informed and believes there are no coal operators operating beds of coal beneath said farm or tract of land on which said well is located, or within 500 feet of the boundaries of the same, who have mapped their workings and filed their maps as required by law, excepting the coal operators or coal owners (if any) above named as addresses.

The above named coal operators or coal owners (if any) are notified that any objections they may desire to make to such proposed location, or which they are required to make by Section 3 of said Code, if the drilling of a well at said proposed location will cause a dangerous condition in or about their respective coal mines, must be received by, or filed with the Department of Mines within ten* days from the receipt of a copy of this notice and accompanying plat by said Department. Said coal operators are further notified that forms for use in making such objections will be furnished to them by the Department of Mines promptly on request and that all such objections must set forth as definitely as is reasonably possible the ground or grounds on which such objections are based and indicate the direction and distance the proposed location should be moved to overcome same.

(The next paragraph is to be completed only in Department's copy.)

Copies of this notice and the enclosed plat were mailed by registered mail, or delivered to the above named coal operators or coal owners at their above shown respective address ________ day__ before, or on the same day with the mailing or delivery of this copy to the Department of Mines at Charleston, West Virginia.

Very truly yours,

UNITED CARBON COMPANY
WELL OPERATOR

JUN 1941
WEST VIRGINIA
DEPARTMENT OF MINES

Address of Well Operator:
BOX 1475
STREET
CHARLESTON
CITY OR TOWN
WEST VIRGINIA
STATE

*Section 3 . . . . If no such objections be filed, or be found by the department of mines, within said period of ten days *from the receipt of said notice and plat by the department of mines*, to said proposed location, the department shall forthwith issue to the well operator a drilling permit reciting the filing of such plat, that no objections have been made by the coal operators to the location, or found thereto by the department, and that the same is approved and the well operator authorized to proceed to drill at said location.

JARRETT PRINTING COMPANY, CHARLESTON, W. VA.

160

JAC-160

OG-10

STATE OF WEST VIRGINIA
DEPARTMENT OF MINES
OIL AND GAS DIVISION

WELL RECORD

Permit No. Jac-160

Oil or Gas Well Gas (KIND)

Company United Carbon Company
Address United Carbon Bldg, Charleston, W.Va.
Farm F.F.Starcher Acres 35.
Location (waters) Station Camp Run, Mill Creek
Well No. 1 Elev. 862.76
District Ripley County Jackson
The surface of tract is owned in fee by
F.F.Starcher Address Huntington, W.Va.
Mineral rights are owned by
F.F.Starcher Address Huntington, W.Va.
Drilling commenced June 13, 1941
Drilling completed Sept. 21, 1941
Date shot 9/21/41 Depth of shot 5161-5201'
Open Flow 32 /10ths Water in 7" O.D. Inch
/10ths Merc. in Inch
Volume 2,394,000 Cu. Ft.
Rock Pressure 1820 lbs 24 hrs.
Oil bbls., 1st 24 hrs.
Fresh water 388 feet 810 feet
Salt water 1445 feet 1455 feet

Casing and Tubing	Used in Drilling	Left in Well	Packers
Size			
16			Kind of Packer
13	764'	000	
10-3/4"	1158'10"	1158'10"	Size of
8 1/4-5/8"	2155'	2155'	
6 5/8 7"	5067'	5067'	Depth set
5 3/16			
3			Perf. top
2-3/8"		5197'	Perf. bottom
Liners Used			Perf. top
			Perf. bottom

CASING CEMENTED 8-5/8" SIZE 720 No. Ft. Date
7" O.D. 207' 8/6/41

COAL WAS ENCOUNTERED AT FEET INCHES
670 FEET INCHES FEET INCHES
FEET INCHES FEET INCHES

Formation	Color	Hard or Soft	Top	Bottom	Oil, Gas or Water	Depth Found	Remarks
Soil			0	16			
Rock	Red		16	30			
Slate			30	60			
Rock	Red		60	120			
Slate			120	125			
Rock	Red		125	175			
Slate			175	180			
Rock	Red		180	245			
Shells			245	260			
Sand			260	280			
Shells			280	315			
Rock	Red		315	340			
Sand			340	420	Water	388'	3 bailers
Rock	Red		420	438			
Slate			438	495			
Rock	Red		495	525			
Slate			525	545			
Sand			545	555			
Rock	Red		555	600			
Slate			600	625			
Sand			625	670			
Coal			670	675			
Slate			675	700			
Sand			700	717			
Slate & shells			717	775			
Sand			775	840			
Slate			840	852			
Rock	Red		852	860			
Slate & shells			860	880			
Sand			880	910			
Rock	Red		910	965			
Slate & shells			965	1010			
Rock	Red		1010	1050			
Slate			1050	1065			
Rock	Red		1065	1075			
Slate & shells			1075	1275			
Sand			1275	1315			
Slate & shells			1315	1350			
Slate	White		1350	1365			
Slate & shells			1365	1370			
Sand			1370	1410			

(Over)

Formation	Color	Hard or Soft	Top	Bottom	Oil, Gas or Water	Depth Found	Remarks
Slate	Black		1410	1428			
Shells			1428	1434	Water	1445'	
Salt Sand			1434	1475	Water	1455'	hole full
Slate			1475	1600			
Sand			1600	1620			
Slate			1620	1640			
Sand			1640	1660			
Slate			1660	1750			
Lime			1750	1765			
Sand			1765	1950			
Lime			1950	2080			
Sand			2080	21 55			
Slate & shells			2155	2960			
Slate	White		2960	3700			
Slate & shells			3700	4040			
Shale			4040	4080			
Slate	White		4080	4200			
Shale	Brown		4200	4270	Gas	4200'	Show
Slate	White		4270	4750			
Shale	Brown		4750	4985			
Shale	Black		4985	5049			
Corniferous Lime			5049	5158			
Oriskany Sand			5158	5212			
Lime			5212	5224			
Sand			5224	5236			
Lime			5236	5244			
Total Depth				5244			

Filled up to 5206'
Shot from 5161'to 5201' With 80 qts. glycerine.

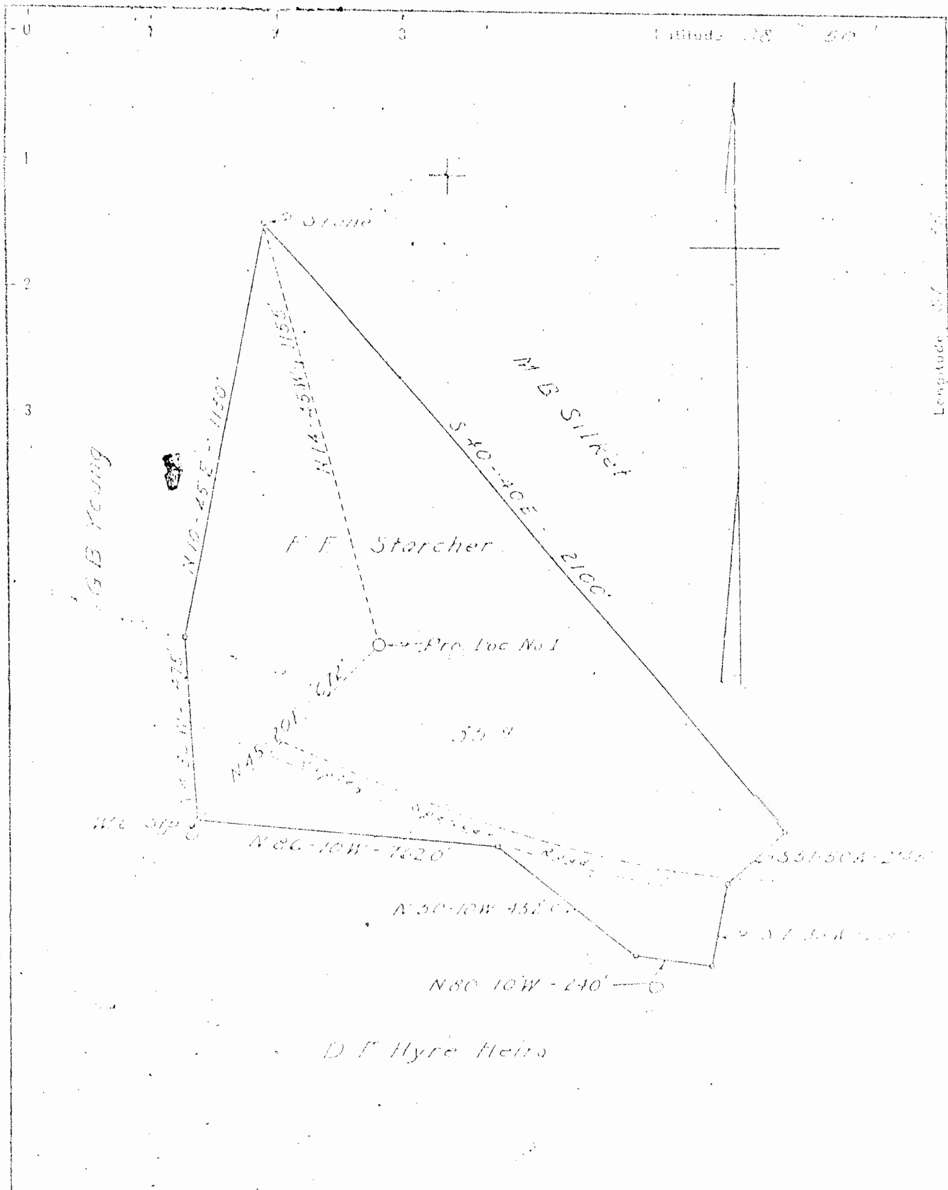
Well drilled by-
S.B.Cart,Drilling Contractor

Drillers-
Rube Pickins
L.E.Sparr

Date Oct 15 [illegible]

APPROVED United Carbon Co. Owner

By Doris Morris Supt (Title)



New Location
Drill Deeper
Abandonment

Company United Carbon Co

Lease No.

Serial No.

District

Drawing No.

STATE OF WEST VIRGINIA
DEPARTMENT OF MINES
OIL AND GAS DIVISION
CHARLESTON

WELL LOCATION MAP

FILE NO.

✣ Denotes location of well on United States Topographic Maps, scale 1 to 62,500, latitude and longitude lines being represented by border lines as shown.

– Denotes one inch spaces on border line of original tracing

00-10

STATE OF WEST VIRGINIA
DEPARTMENT OF MINES
OIL AND GAS DIVISION

WELL RECORD

Permit No. [illegible]

Oil or Gas Well GAS (KIND)

Company COLUMBIAN CARBON COMPANY
Address Box 1210, Charleston, W. Va.
Farm Minnie B. Silket, etal Acres 162
Location (waters) Stationcamp Run
Well No. 1 (GW-605) Elev. 762.0 DF
District Ripley County Jackson
The surface of tract is owned in fee by Minnie B. Silket
Address Liverpool, W. Va.
Mineral rights are owned by "Same"
Address
Drilling commenced 8-13-41
Drilling completed 2-13-42
Date Shot 2-19-42 From 5073 To 5133
With 600# 80% Gelatin
Open Flow /10ths Water in Inch
/10ths Merc. in Inch
Volume 747 Cu. Ft.
Rock Pressure 275 lbs. 1 hrs.
Oil bbls., 1st 24 hrs.
Fresh water 297' 2-15" Blrs./Hr., 590' 4-13" Blrs./Hr. feet
Salt water 1300' 2-10" Blrs./Hr., 1765' Hole Full feet

Casing and Tubing	Used in Drilling	Left in Well	Packers
Size			
16"	41'3"	41'3"	Kind of Packer
13 3/8"	430'9"	430'9"	
10 3/4"	1104'8"	1104'8"	Size of
8 5/8"	2084'1"	2084'1"	
7"	5004'11"	5004'11"	Depth set
5 3/16			
3			Perf. top
2 3/8"	5082'7"	5082'0"	Perf. bottom
Liners Used			Perf. top
5 3/16"	92'5"	92'5"	Perf. bottom

CASING CEMENTED .... SIZE .... No. Ft. .... Date

See Reverse Side

COAL WAS ENCOUNTERED AT .... FEET .... INCHES

.... FEET .... INCHES .... FEET .... INCHES

.... FEET .... INCHES .... FEET .... INCHES

Formation	Color	Hard or Soft	Top	Bottom	Oil, Gas or Water	Depth Found	Remarks
Red Rock			0	50			
Blue Slate			50	60			
Red Rock			60	70			
Blue Slate			70	89			
Red Rock			89	95			
Lime			95	110			
Slate			110	125			
Red Rock			125	154			
Slate & Shells			154	265			
Water Sand			265	318	Fresh Water	297	2-15" Blrs./Hr.
Red Rock			318	345			
Lime			345	394			
Red Rock			394	400			
Lime			400	420			
Red Rock			420	437			
Sandy Lime			437	445			
Red Rock			445	460			
Slate & Shells			460	490			
Red Rock			490	513			
Slate & Shells			513	523			
Red Rock			523	542			
Shells			542	555			
Sand			555	600	Fresh Water	590	4-13" Blrs./Hr.
Blue Slate			600	610			
Coal			610	612			
Slate Shells			612	662			
Sand			662	692			
Slate			692	725			
Red Rock			725	750			
Slate Shells			750	795			
Sand			795	815			
Slate Shells			815	825			
Red Rock			825	880			
Slate & Shells			880	926			
Red Rock			926	991			
Sandy Lime			991	1020			
Red Rock			1020	1030			
White Slate			1030	1050			
Yellow Rock			1050	1057			
Slate			1057	1095			
Sandy Lime			1095	1130			
Slate & Shells			1130	[illegible]			

MAR 1942
WEST VIRGINIA
DEPARTMENT OF MINES

(Over)

Robert W. Rutta

(Over)

Formation	Color	Hard or Soft	Top	Bottom	Oil, Gas or Water	Depth Found	Remarks
Sand-			1194	1229			
Slate & Shells			1229	1243			
Lime Shells			1243	1284			
Sand			1284	1342	Salt Water	1300	2-10" [illegible]/Hr.
Slate			1342	1409			
Sand			1409	1424			
Slate			1424	1492			
Sand			1492	1510			
Slate			1510	1650			
Slate Shells			1650	1689			
Salt Sand			1689	1778	Salt Water	1765	Hole Full
Slate			1778	1780			
Lime			1780	1818			
Sand			1818	1857			
Big Lime			1857	2003			
Big Injun Sand			2003	2074	2084'-8¼"		
Lime			2074	2100			
Slate			2100	2151			
Lime			2151	2194			
Slate & Shells			2194	2450			
Berea Shells			2450	2470	Gas	2450	Show
Slate & Shells			2470	2900			
White Slate			2900	3180			
Brown Shale			3180	3250			
Slate & Shells			3250	3678			
Brown Shale			3678	3698			
Slate & Shells			3698	4638			
Slate			4638	4718			
Brown Shale			4718	4922	Gas	4750	Show
Black Shale			4922	4954 SLM			
Corniferous Lime			4954 SLM	5073 SLM	5005' 7"		
Oriskany Sand			5073 SLM	5133			
Lime			5133	5146			
Oriskany Sand			5146	5157			
Lime			5157	5160 SLM			
					PAYS: 5084	5094-98	
TOTAL DEPTH				5160 SLM			

CEMENT RECORD:

8-18-41 Aquagelled 13-3/8" casing. Ran 12 sacks 6% aquagel and 1 sack Fibrotex. Returns at 364'. F. M. Mills, Cementer - Halliburton Oil Well Cementing Co.

9-3-41 Aquagelled 10-3/4" casing. Ran 20 sacks 6% aquagel and 1 sack Fibrotex. Ran 10" plug. No circulation. F. M. Mills, Cementer - Halliburton Oil Well Cementing Co.

9-19-41 Cemented 8-5/8" casing. Ran 61 sacks Superior cement and 1 sack aquagel. Worked string up and down hole while cement was going around pipe. [illegible] to [illegible] to bottom [illegible]. Circulation at zero feet. Walter Riley, Cementer - Halliburton Oil Well Cementing Co.

2-2-42 Cemented 7" casing. Ran 12 sacks Superior cement in dump bailer. 65' cement in pipe. Columbian Carbon Company crew

Date March 23, 1942

APPROVED COLUMBIAN CARBON COMPANY, Owner

By D. W. Van Patten Supt. (Title)

Robert W. Rutta

STATE OF WEST VIRGINIA
DEPARTMENT OF MINES
OIL AND GAS DIVISION

WELL RECORD

Permit No. Jac-200

Oil or Gas Well GAS (KIND)

Company COLUMBIAN CARBON COMPANY
Address Box 1240, Charleston, W. Va.
Farm G. B. Young, et al Acres 205
Location (waters) Branch of Stationcamp Run
Well No. 1 (GN-611) Elev. 751.6 DF
District Ripley County Jackson
The surface of tract is owned in fee by G. N. Steinhoff
Address Ripley, W. Va.
Mineral rights are owned by
Address
Drilling commenced 9-16-41
Drilling completed 12-13-41
Date Shot 12-14-41 From 5051' SLM To 5106' SLM
With 550# 80% Gelatin
Open Flow /10ths Water in Inch
/10ths Merc. in Inch
Volume 1,057M Cu. Ft.
Rock Pressure 1590 lbs. 5 Days hrs.
Oil bbls., 1st 24 hrs.
Fresh water 65' 4-13" Blrs./Hr.; 735' 1½-13" Blrs./Hr. feet
Salt water 1340' Filling up; 1360' Hole Full feet

Casing and Tubing	Used in Drilling	Left in Well	Packers
Size			
16"	40'7"	40'7"	Kind of Packer
13-3/8"	672'5"	Pulled	No Packer
10-3/4"	1193'5"	Pulled	Size of
8-5/8"	2144'7"	2144'7"	
6⅝ 7"	4994'1"	4994'1"	Depth set
5 3/16			
3			Perf. top
2-3/8"	5134'1"	5134'1"	Perf. bottom
Liners Used			Perf. top
3½"	92'6"	92'6"	Perf. bottom

CASING CEMENTED SIZE No. Ft. Date
See Reverse Side

COAL WAS ENCOUNTERED AT FEET INCHES
FEET INCHES FEET INCHES
FEET INCHES FEET INCHES

Formation	Color	Hard or Soft	Top	Bottom	Oil, Gas or Water	Depth Found	Remarks
Red Rock			0	50			
Sand			50	70	Fresh Water	65	4-13" Blrs./Hr
Red Rock			70	80			
Sand			80	95			
Red Rock			95	130			
Sand			130	165			
White Slate			165	175			
Lime			175	200			
Red Rock			200	210			
Lime			210	215			
Red Rock			215	250			
Sand			250	320			
Red Rock			320	330			
Lime			330	340			
White Slate			340	380			
Red Rock			380	465			
Lime			465	490			
White Slate			490	515			
Sand			515	565			
Slate			565	615			
Lime			615	625			
Slate & Shells			625	655			
Sandy Lime			655	676			
Sand			676	740	Fresh Water	735	1½-13" Blrs./Hr
Red Rock			740	755			
Slate			755	780			
Sand			780	790			
Red Rock			790	830			
White Slate			830	855			
Sand			855	877			
White Slate			877	900			
Red Rock			900	922			
White Slate			922	934			
Red Rock			934	945			
White Slate			945	970			
Red Rock			970	980			
Sand			980	995			
Red Rock			995	1056			
Red Rock			1056	1066			
Slate			1066	1066			
Sand			1066	1089			
Slate			1089	1161 SLM			

FEB 1942
WEST VIRGINIA
DEPARTMENT OF MINES

(Over)

Robert W. Rutta

Formation	Color	Hard or Soft	Top	Bottom	Oil, Gas or Water	Depth Found	Remarks
Sand			1181 SLM	1191			
Slate			1191	1240			
Lime			1240	1250			
Sand			1250	1306			
Black Slate			1306	1325			
Sand			1325	1350	Salt Water	1340-45	Filling up
Slate			1350	1365	Salt Water	1360	Hole Full.
Lime			1365	1385			
Black Slate			1385	1395			
Lime			1395	1400			
Slate & Shells			1400	1480			
Sand			1480	1495			
Slate & Shells			1495	1676			
Salt Sand			1676	1815			
Black Slate			1815	1820			
Big Lime			1820	1948			
Sand			1948	2023			
Black Slate			2023	2025			
Limestone			2029	2071			
Slate & Shells			2071	2407			
Brown Shale			2407	2433			
Berea Grit			2433	2455			
Slate & Shells			2455	3694			
Brown Shale			3694	3821			
White Slate			3821	3964			
Brown Shale			3964	4083			
White Slate			4083	4108			
Brown Shale			4108	4270			
White Slate			4270	4665			
Brown Shale			4665	4900			
Black Shale			4900	4942 SLM			
Corniferous Lime			4942 SLM	5048 SLM			
Oriskany Sand			5048 SLM	5106 SLM			
Limestone			5106 SLM	5114			
Oriskany Sand			5114	5125 SLM			
TOTAL DEPTH				5125 SLM			

PAY: 5049-52; 5065-72; 5079-88

CEMENT RECORD:

9-24-41	Aquagelled 13-3/8" casing. Ran 5 sacks Aquagel and 1 sack Fibrotex. Circulation at 431'. Picked pipe up and set back on bottom. Cecil Watkins, Cementer - Halliburton Oil Well Cementing Co.
10-1-41	Aquagelled 10-3/4" casing. Ran 10 sacks Aquagel and 1 sack Fibrotex. Circulation at 812'. Picked up pipe and worked up and down when Aquagel started around bottom of pipe. F. M. Mills, Cementer Halliburton Oil Well Cementing Co.
10-30-41	Cemented 8-5/8" casing. Ran 118 sacks Superior cement and 2 sacks Aquagel. Ran plug ahead of cement and plug following cement. Ran 10' spacer on bottom of top plug. 20' cement in pipe. S. K. Johnson, Cementer - Halliburton Oil Well Cementing Co.
12-1-41	Cemented 7" casing. Ran 12 sacks Superior cement in dump bailer. 50' cement in pipe. Columbian Carbon Company crew.

Date February 14, 1942

APPROVED COLUMBIAN CARBON COMPANY, Owner

By C. W. Van Patten, Sup't.
(Title)

Integrating Fracture-Mapping Technologies To Improve Stimulations in the Barnett Shale

M.K. Fisher, SPE, **C.A. Wright,** SPE, and **B.M. Davidson,** SPE, Pinnacle Technologies; **A.K. Goodwin,** SPE, **E.O. Fielder,** SPE, **W.S. Buckler,** SPE, and **N.P. Steinsberger,** SPE, Devon Energy Corp.

Summary

A large hydraulic-fracture diagnostic project was undertaken in the summer of 2001 that integrated fracture-diagnostic technologies, including tiltmeter (i.e., surface and downhole) and microseismic mapping. The extensive data gathered resulted in a much clearer understanding of the highly complex fracture behavior in the Barnett shale of north Texas. The detailed fracture-mapping results allowed construction of a calibrated 3D fracture simulator that better reflects the observed mechanics of fracturing in this fractured-shale reservoir. More than just simple calibration was required. Indeed, a whole new understanding of fracture growth was developed.

The Barnett shale has seen a rebirth of drilling and refracturing activity in recent years because of the success of waterfracture, or "light-sand," fracturing treatments. This extremely low-permeability reservoir benefits from fracture treatments that establish long and wide fracture "fairways," which result in connecting very large surface areas of the formation with an extremely complex fracture network.

Understanding the created-fracture geometry is key to the effectiveness of any stimulation program or infill-drilling program, particularly in this area, with its nonclassical fracture networks. Integrated-fracture diagnostics have led to the identification of new fracturing techniques, as well as additional refracturing and infill-drilling candidates. A new method for evaluating large microseismic data sets was developed. Combining the microseismic analysis with surface- and downhole-tilt fracture mapping allowed characterization of the created-fracture networks. Correlations between production response and various fracture parameters will be presented along with a discussion of methods for calibrating a fracture model to the observed fracture behavior.

Barnett Basics

The Mississippian-age Barnett shale is a marine shelf deposit that unconformably lies on the Ordovician-age Viola limestone/Ellenburger group and is conformably overlain by the Pennsylvanian-age Marble Falls limestone. The Barnett shale within the Fort Worth basin ranges from 200 to 800 ft in thickness and is approximately 500 ft thick in the core area of the field. The productive formation is typically described as a black, organic-rich shale composed of fine-grained, nonsiliciclastic rocks with extremely low permeability, ranging from .00007 to .005 md. The formation is abnormally pressured, and hydraulic-fracture treatments are necessary for commercial production because of the low permeability.

The first decade of Barnett shale stimulation treatments was dominated by massive hydraulic-fracture treatments (more than one million lbm of proppant carried by highly viscous gel systems). Production was variable, with wells producing up to 1 Bcf estimated ultimate recovery. In 1997, Devon Energy (formerly Mitchell Energy) began experimenting with waterfractures, or light-sand, fracturing treatments, which were at the time, being successfully applied in the Cotton Valley sandstone—a tight gas reservoir approximately 100+ miles to the east of the Fort Worth basin.[1] The waterfractures were successfully reintroduced into the Cotton Valley because of the then-current lack of commercial viability for large, expensive cross-linked fracture treatments in that reservoir. Devon believed that similar success would be achieved in the Barnett shale with large-volume slickwater treatments and subsequently experimented with several versions of these treatments before evolving to the current design. Today, depending on the location within the Barnett, viability of limestone barriers surrounding the Barnett intervals, and net-pay thickness, a "typical" Barnett treatment may consist of 750,000 gal of slickwater and 80,000 lbm of proppant pumped at 60 bpm, with proppant concentrations averaging 0.1 to 0.5 ppg throughout the treatment. The lack of gel solids in the fracturing fluid is believed to contribute to longer, more complex fractures and additionally, leave no gel residue or filter cake behind that may damage the fracture conductivity in these treatments. Because of the low-permeability nature of the reservoir, it is imperative that extremely large fracture-surface areas are created by the fracture treatments. The use of light-sand, or waterfracture, treatments has considerably improved both the production performance and the economics in this reservoir. Because of its extremely low permeability, the drainage distance from the fracture face is very small.

Introduction

The classical description of a hydraulic fracture is a single biwing planar crack with the wellbore at the center of the two wings. However, almost all physical fracture verifications performed to date, from corethroughs to minebacks, have proved this description to be oversimplified. Therefore, fracture-mapping technologies can provide insight into reservoir-depletion dynamics and significantly help optimize reservoir management. Fractures can be categorized as simple (the classical description), complex, or very complex. An illustration of how these fractures may look is found in **Fig. 1.**

Because of several factors, including the presence of natural fractures, a fracture treatment in the Barnett is more likely to look like the "very complex" fracture description than the "simple" case. This allows a fracture fairway to be created during a treatment with many fractures in multiple orientations, resulting in large surface areas potentially contributing to production. Numerous treatments have been mapped in the Barnett to gain a better understanding of how these fractures propagate.

The primary (i.e., hydraulic) fracture orientation is northeast (NE) to southwest (SW) in this area. This has been verified from both surface tiltmeters and microseismic-fracture mapping. Additionally, many secondary fractures identified from oriented core and borehole-imaging surveys in this area are oriented orthogonal to the primary fracturing [northwest (NW) to southeast (SE)],[2] and these natural fractures may be activated (i.e., opened) during a hydraulic-fracture treatment. The length and width of the resulting fracture fairway is important in determining the area contacted by the fracture so that well location and spacing can be optimized. Because of the aforementioned small drainage distance from a fracture, the density of fractures within this fairway is very important. There may be opportunities for additional wells to be drilled in less-densely fractured areas within a fracture fairway or

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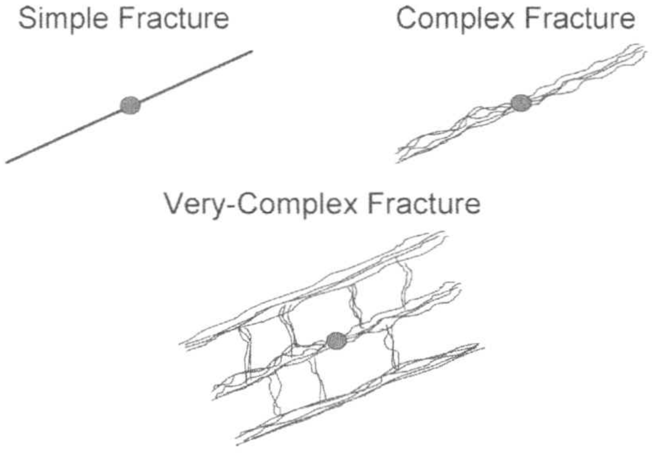

Fig. 1—Fracture complexity.

for refractures to be performed that may extend the fairway or more-densely populate it with new fractures.

Fracture-Mapping Technologies

A combination of fracture-mapping technologies was used to develop an accurate image of fracture growth in the Barnett. These complementary technologies allowed for a better understanding of the different aspects of fracture growth. Production results strongly correlated to the orthogonal fracture growth, visible in the surface tiltmeters as the NW component, and in the microseismic data as a wide band of seismic activity. Using two independent mapping technologies allowed for a more-complete image of the fracture fairway. **Table 1** shows the components of fracture geometry determined from each of the mapping technologies.

Surface Tiltmapping. This is a fracture-diagnostic tool used around the world on more than 1,000 treatments per year to map the deformation caused at the surface of the Earth by hydraulic fractures or dislocations in the subsurface. The tiltmeter is a very sensitive device—similar to an electronic carpenter's level—that can sense changes in the gradient of displacement (or tilt) as small as one part per billion. Surface deformation, measured by tiltmeter arrays, is used to directly determine the azimuth and dip of a hydraulic fracture and also the percent of treatment volume placed in each plane or orientation when fracture growth occurs in multiple planes.[3] Approximately 30 surface tiltmeter sites were required in each of the mapping areas on the basis of depth of the

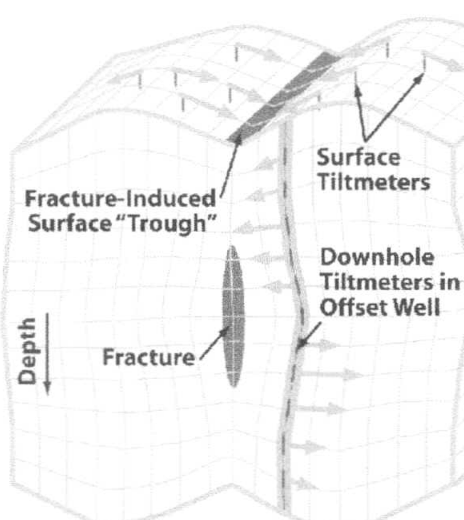

Fig. 2—Deformation pattern resulting from hydraulic fracture.

TABLE 1—BARNETT FRACTURE-GEOMETRY MEASUREMENTS DETERMINED BY VARIOUS TECHNOLOGIES

	Surface Tilt	Downhole Tilt	Microseismic
Azimuth	X		X
Height		X (tip)	X (wellbore)
Length		X	
Asymmetry		X	
NW Volume Component	X		

fracture treatments, the expected fracture complexity, and the large area encompassing the number of wells stimulated in each field.

Downhole Tiltmapping. This is a separate application of the same technology.[4,5] By ruggedizing the surface tiltmeter instruments and placing them in offsetting wellbores to the treatment wells, hydraulic-fracture dimensions can be determined. Most of the treatments were monitored with two downhole tiltmeter arrays near the end of each wing of the fracture fairway to determine the location of fracture top and bottom and the total length of each wing. To measure fracture length, the downhole tiltmeter arrays are placed in the general direction the fractures are expected to propagate. The tiltmeter cube illustrated in **Fig. 2** shows the expected deformation pattern resulting from a simple hydraulic fracture, as seen at the surface and from an offset wellbore.

Microseismic Mapping. This has been used for more than 20 years to measure the location of microearthquakes, or microseisms, which result from the placement of a hydraulic fracture.[6] These small slippages are detected by a vertical array of five to 12 sensitive listening devices, such as geophones or accelerometers, placed in an offsetting wellbore. After orienting each tool in the array (normally, the perforating procedure in the treatment well is used to orient the three-component sensors), the microseisms created by the fracture treatment are detected, oriented, and located within the reservoir. As the treatment proceeds, a map of the event locations develops, which provides measurements of the fracture azimuth and dimensions. An illustration of the general concept of microseismic-fracture mapping is seen in **Fig. 3.**

Barnett Examples

Surface tiltmapping was used to determine the primary and secondary fracture orientation and the fractional volume of fracturing slurry placed in each orientation. The wide, shaded rectangle in **Fig. 4** is the primary-fracture length (from downhole tiltmapping) and orientation (surface tiltmapping), while the "crossties" indicate the volume of fluid placed into the secondary (i.e., natural) -fracture orientation with each crosstie representing 5% of the total slurry volume (i.e., 45% in the NW direction on this fracture). Microseismic events are represented by the orange points in this plan view, and as can be seen on this treatment, this fracture fairway is very wide—approximately 900 ft across.

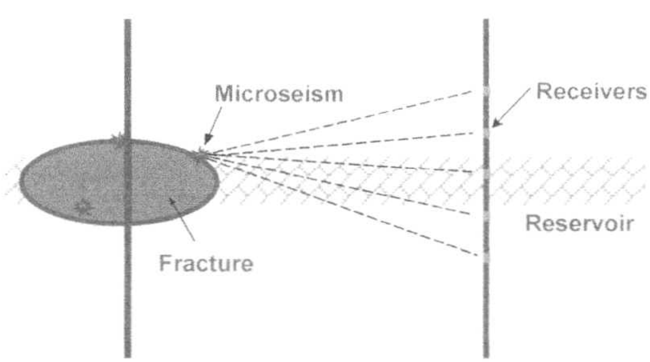

Fig. 3—Microseismic-event location.

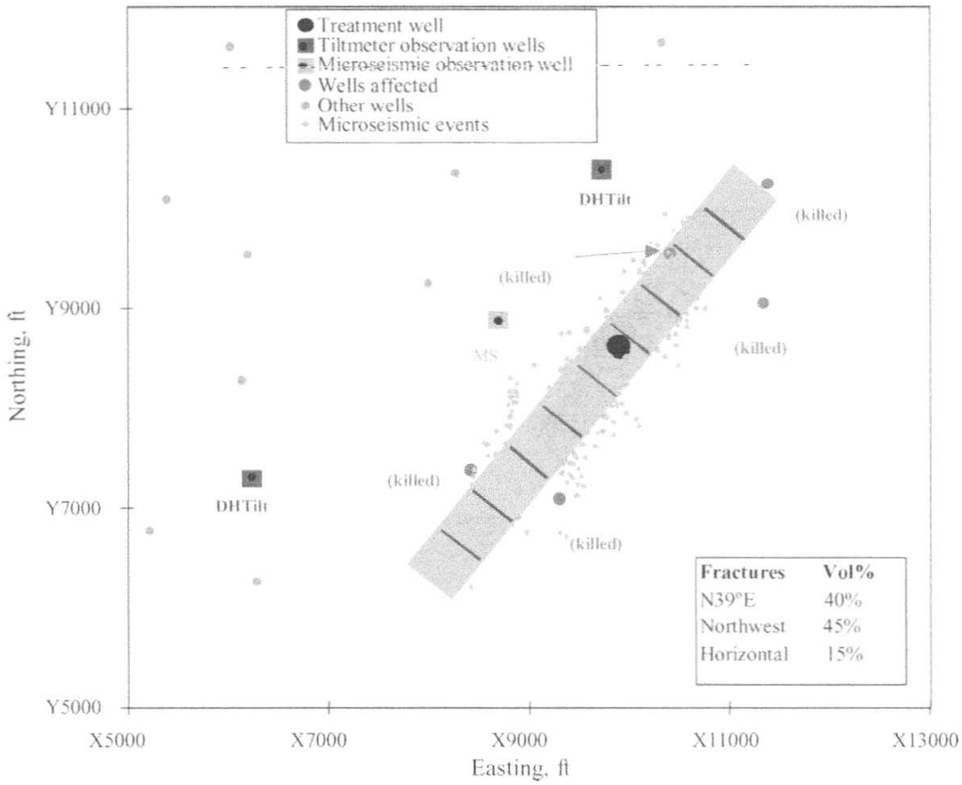

Fig. 4—Plan view of one of the mapped fields showing the orientation of a Barnett fracture fairway and the tilt-measured fracture volume in the various fracture planes.

A new technique was developed to look at multiple fracture growth with time. Small sequential increments (in this case, 40 events) of microseismic data are fitted into a linear-regression model to determine the length and orientation of the many fracture segments in the order that they are created. Using this approach enabled us to match the primary- and secondary-fracture azimuths measured by surface tiltmeters, as well as give an estimate of the total fracture-segment length of all mapped fractures (more than 25,000 ft in many treatments). A number of nearby wells were killed or affected because of fracture-to-wellbore or fracture-to-fracture intersections during this treatment, providing physical evidence of the geometry of these fracture networks (see **Fig. 5**).

The fracture treatment shown in **Fig. 6** is in the lower Barnett shale and is mostly confined within the lower Barnett. The fracture-fairway half-length is very long, approximately 2,500 ft. Downhole tiltmeters placed past the tip of each wing of the fairway were used to determine fairway half-length. The microseismic-monitor well was near the center of the fracture and unable to see out to the very ends of the fairway because of attenuation of the microseismic signals over these extremely long distances. This fracture treatment covered the entire targeted pay and created a wide and complex fairway with fractures growing in multiple orientations. The smaller internal ovals show fracture geometry (i.e., height and length) measured by downhole tiltmeters at the ends of the fairway, while the individual points are microseismic events measured by an array perpendicular to the center of the fracture fairway. The large, translucent-shaded area is the integrated-fracture geometry from combining the highest-confidence measurement for each fracture parameter. This geometry was used to create a calibrated 3D fracture model for this area. Combining fracture-diagnostic technologies from different location perspectives is often useful in ensuring that we use all of the fairway in maximizing net present value.

The map view in **Fig. 7** shows the microseismic results from seven mapped fracture treatments in the lower Barnett. After taking into account the observation well locations to remove any bias caused by the position of the observation-well relative to the fracture, several "holes" in the fracture fairway are visible, as shown by the ellipses in Fig. 7. These holes in the fairways may be caused by a number of different factors: for example, lithologies that are microseismically aseismic or a lack of fracture network in these local areas, which makes them possible targets for refracturing treatments or even new drilling locations, to more-completely drain this field.

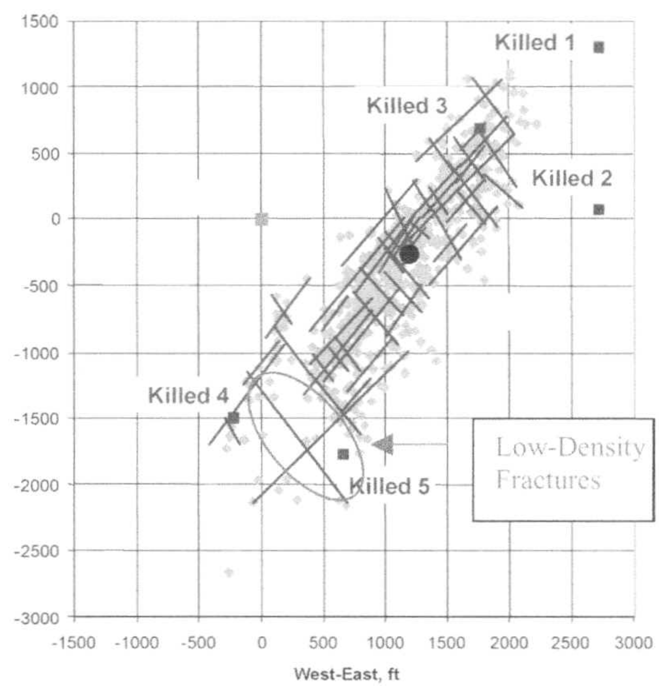

Fig. 5—Plan view of fracture-structure plot from one treatment showing the size and complexity of fracture segments in the hydraulic (NE/SW)- and natural (NW/SE)-fracture orientations.

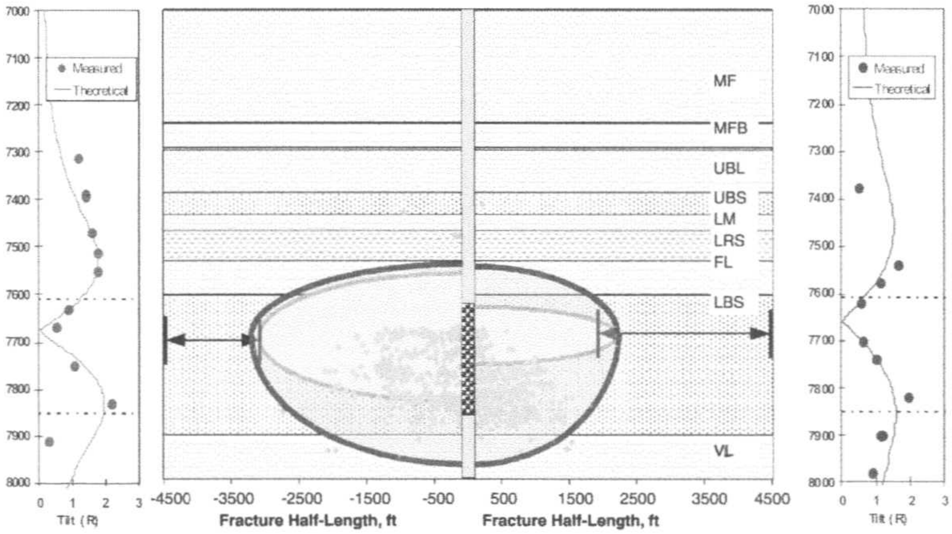

Fig. 6—Side view of a lower Barnett fracture treatment viewed from the normal to the hydraulic-fracture fairway (as seen from the SE).

Summary of Mapped-Fracture Geometries

Two different treatment designs were performed in these areas: two separate stages targeting the lower and upper Barnett independently, and "combo" treatments targeting both lower and upper Barnett pays with one treatment. As seen, the fracture-fairway lengths, in general, are longer on the separate-stage treatments than on the combo fractures, and the fairway width is also greater on the individual treatments than on the combo fractures.

Correlation of Fracture Parameters to Production

As seen in **Fig. 8,** the productivity of the wells was not greatly influenced by the conventional-fracture half-length. This was perplexing at first because it is the opposite of what one would expect from a low-permeability reservoir. However, this led to evaluating other fracture parameters and their influence on productivity.

The growth of the fracture-fairway half-length was evaluated as a function of fluid volume **(Fig. 9).** The fracture's half-length stops growing on nearly all fractures after a significant fluid volume is pumped. The microseismic-measured half-length is shorter because of the position of the observation well and attenuation of acoustic signals over these very long fairway lengths. However, both mapping methods indicated an arresting of the fracture half-length before the end of the treatment.

The lack of fracture-length growth in the later portions of the treatment appeared to justify the reduction of the treatment volumes until the fracture network was evaluated in greater detail. The width of the fracture network was observed in both the surface tiltmeters (NW component) and in the microseismic activity in

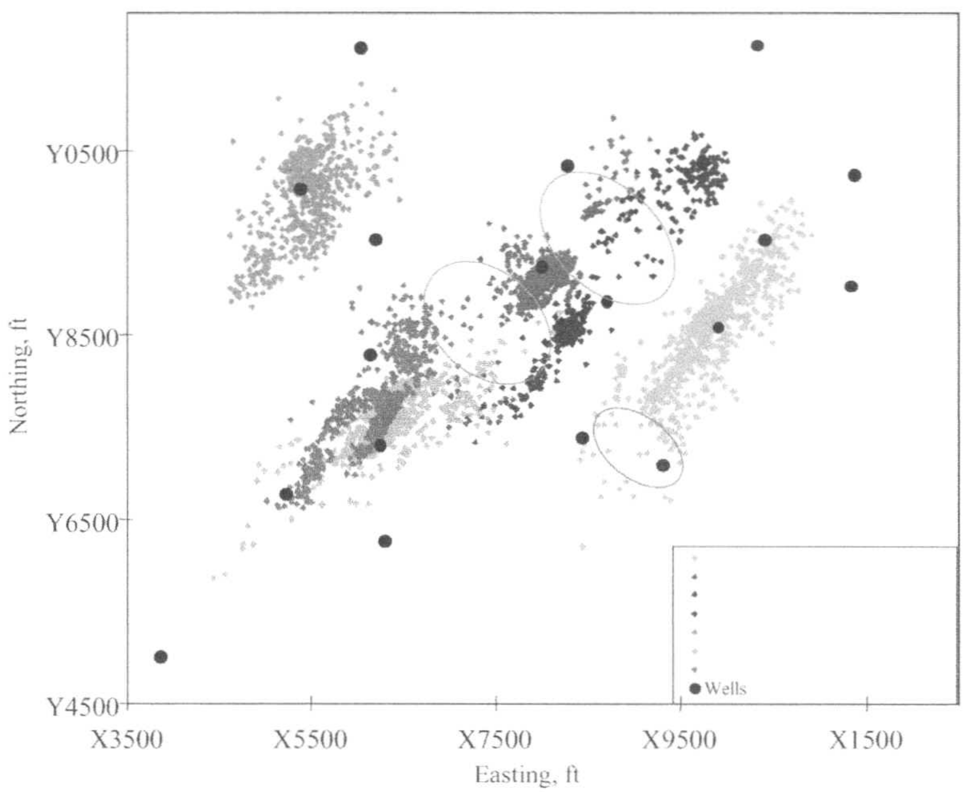

Fig. 7—Plan view of seven fracture treatments in one field illustrating the holes or "sand traps" in several of the fracture fairways.

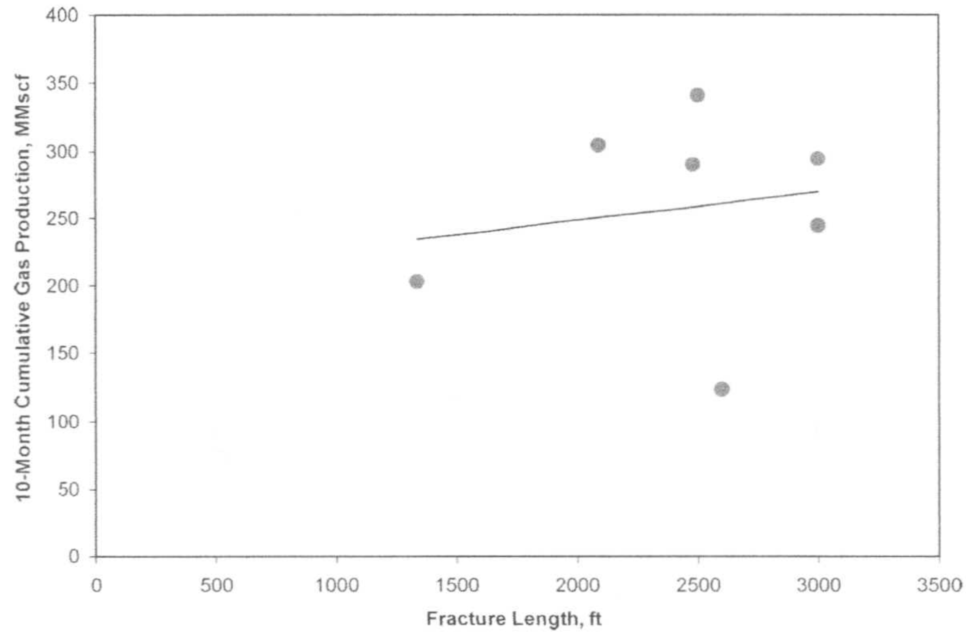

Fig. 8—Graph illustrating the lack of correlation of fracture-fairway half-lengths to early production results.

which growth was observed in a wide band of events. As seen in **Fig.10,** the wider the fracture network, the better the productivity from the well.

The total length of the fracture network was determined by summing the microseismic-fracture structure segments over time. It was immediately apparent that significant individual fracture networks were developing as each treatment progressed. As seen in **Fig. 11,** the total fracture-network system continued to grow with additional pumped volume. Therefore, to improve well productivity, a larger fracture-network system is desirable, independent of the conventional-fracture half-length.

The summary table (Table 2) of fracture geometries, and the correlations shown in this section, illustrates that the half-length of the fracture fairway is not the most critical parameter influencing early production. The mapping data show that individual fracture stages in the Barnett typically produce longer and wider fracture networks, while correlations of treatment volumes to created fracture-fairway half-lengths are not strong. The correlations of treatment volume to fairway width, and of fairway width to early production, do indicate that larger fracture treatments tend to produce larger surface areas. This has a favorable effect on production.

Fracture-Model Calibration

The fracture-engineering portion of this project consisted of minifracture analysis with step-down tests, fracture modeling, and postfracture analysis of treatment and production data. An investigation of the mapping results indicates that initial well productivity was independent of the fracture half-length; however, there appears to be a correlation to the size and complexity of the created fracture network. Other production correlations that helped support

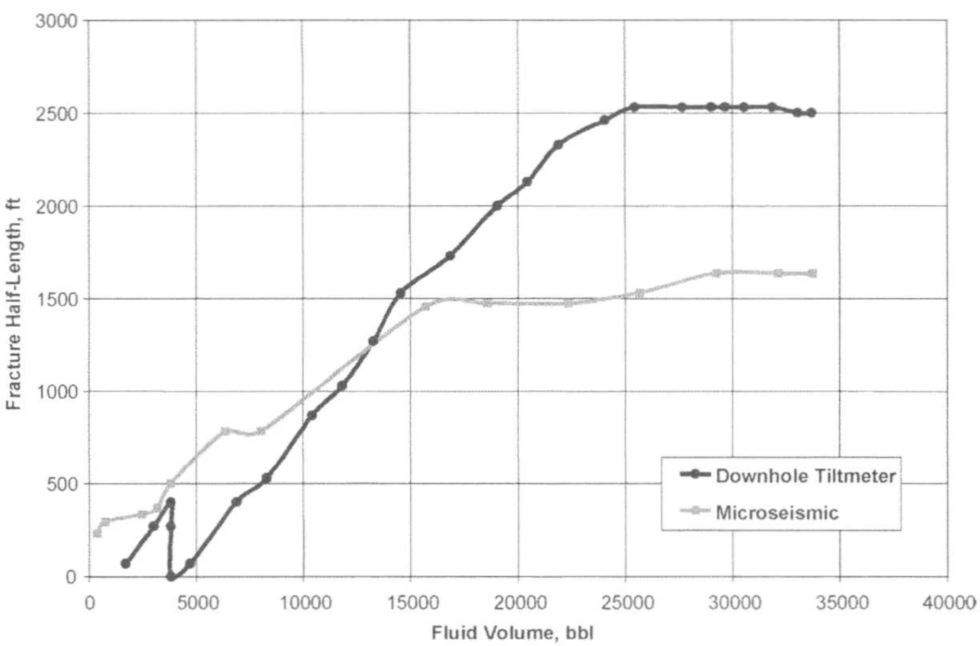

Fig. 9—Graph illustrating growth of fracture-fairway half-lengths as a function of treatment volume on one Barnett "combo-fracture" well.

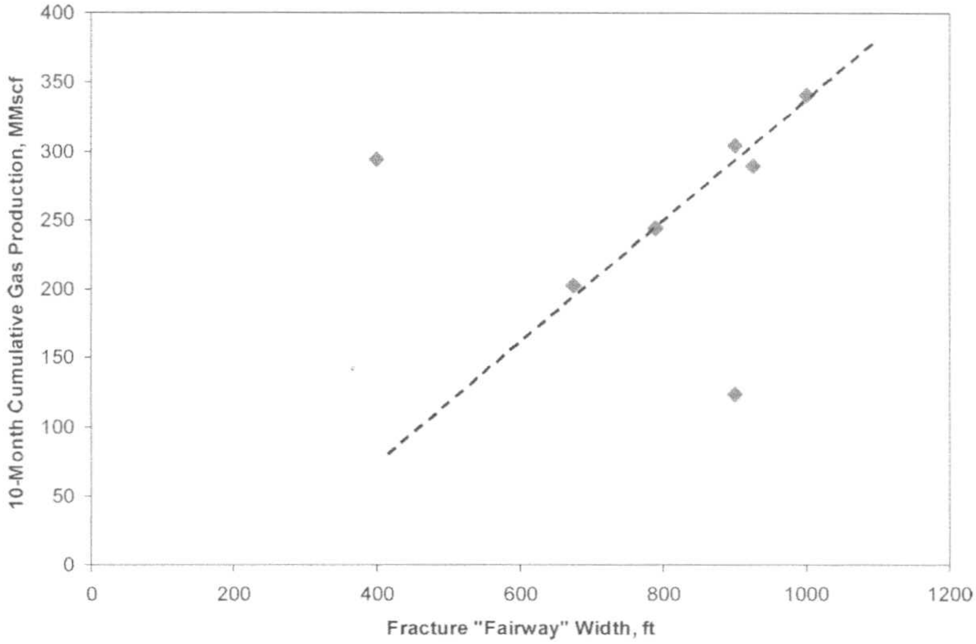

Fig. 10—Shows positive correlation of fracture-fairway width (degree of fracture complexity and total fracture surface area) to early production results.

this finding that fracture complexity was the primary driver for productivity included the NW fracture-component volume from surface tiltmeters (i.e., crosscutting natural fractures), fracture-network width (i.e., microseismic event's width), and the degree of net pressure increase during the job.

One of the benefits of direct fracture-geometry measurements is having the ability to calibrate a fracture model. This results in an effective modeling tool for optimizing future designs of hydraulic-fracture treatments. While fracture diagnostics are critical for understanding how fractures grow, modeling is required to predict the performance of future designs and to evaluate design changes. The previously discussed measured-fracture geometries were used to develop a calibrated model for the Barnett shale in two different areas. A variable-height fracture simulator was used to model the measured-fracture geometry while incorporating the treating pressure, volume, and rates. To achieve a match, several of the input calibration parameters, or settings, were adjusted from the default values. The final calibrated model settings were then capable of predicting growth in all single-zone treatments and are reasonable for application in the combo treatments.

Three main "modeling physics" parameters were adjusted to history match the observed net pressure and fracture geometry, as measured by the mapping technologies. These parameters were the crack-opening coefficient, tip-effects coefficient, and tip-effects scale volume. The same calibration settings were then used for all treatments, and net-pressure matches honored fracture-treatment parameters, as well as the new calibrated settings.

A lower value of the crack-opening coefficient was required to reduce the pressure gradient along the fracture length, decreasing the average net pressure in the fracture for the same wellbore net

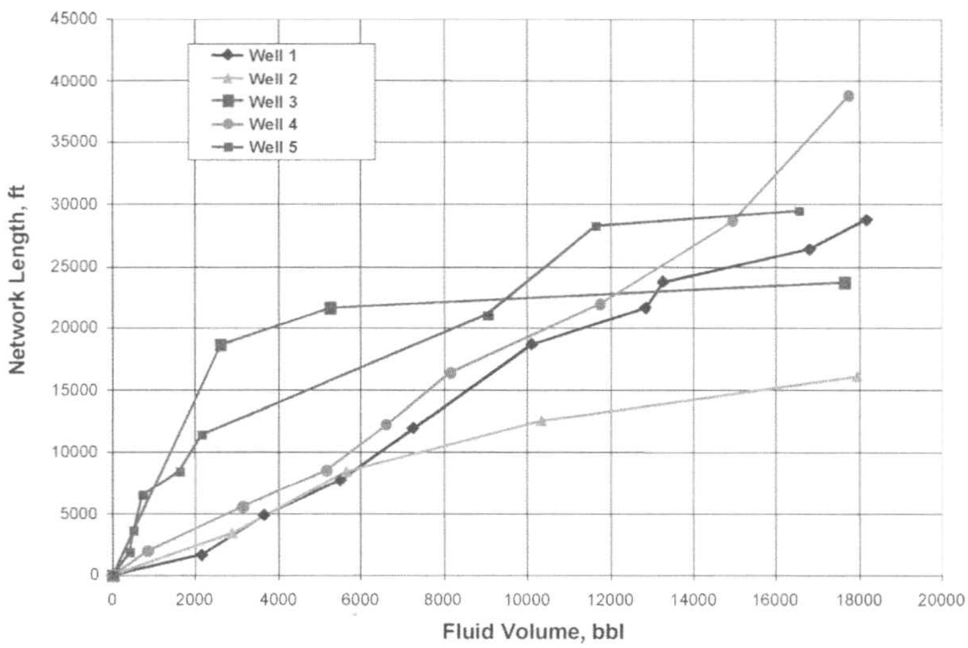

Fig. 11—Graph showing correlation of total fracture-network length to pumped fluid volume in lower Barnett—in most cases, network length grows with incremental treatment volume.

TABLE 2—SUMMARY OF FRACTURE GEOMETRY FROM 16 FRACTURE TREATMENTS

Well	Half-Length SW, ft	Fracture Height: Tip SW, ft	Fracture Height: Wellbore, ft	Fracture Height: Tip NE, ft	Half-Length NE, ft	Fracture: Azimuth NE, Degrees	Fracture: Network Width, ft	Composite: Half-Length, ft	Composite: Height, ft
Lower Barnett Average	2,875	248	311	211	2,600	46	802	2,775	386
Upper Barnett Average	3,033	197	326	197	2,500	47	900	2,850	517
Lower Combo Average	2,391	400	458	400	2,391	49	598	2,391	583
Upper Combo Average	2,124				2,124				

Asymmetrical fractures based on downhole tiltmeter.

pressure. This allows for modeling both high net pressures and long fracture half-lengths. The crack-opening coefficient also controls shear decoupling. The lower value simulates fracture slipping at the fracture cleats. Typically, the pressure at the wellbore acts as a force wedging open the entire length of the fracture. However, in a highly fractured system, the force is not transmitted efficiently along the length of the fracture because the force dissipates as it crosses each fracture. In fracture modeling, this is referred to as "decoupling."

The tip-effects coefficient was increased to reduce the estimated pressure at the tip of the fracture, which is plausible in highly fractured reservoirs. The tip-effects scale volume was increased to delay when the tip effects reach the maximum. This allows for the tip effects to be gradually stepped with time.

The net pressure was history matched for each fracture treatment. An example of the net-pressure match for a single zone (lower Barnett shale fracture treatment) is shown in **Fig. 12.** The model matches the magnitude and character of the net pressure throughout the treatment.

The modeled fracture geometry is shown in **Fig. 13.** As seen from the mapping measurements, tiltmeter, and microseismic, the fracture is fairly well contained to the lower Barnett and does not grow up to the upper Barnett shale.

Table 3 shows the calibrated-fracture-model results vs. the composite measured-fracture dimensions for the various treatments. The settings developed for the calibrated model do a very good job of matching the single-zone upper Barnett and lower Barnett treatments, especially for the fracture half-lengths. It is more difficult to model the combo fractures because of the differences in closure pressure and changing fluid split rates; however, the model still works reasonably well for the combo fractures.

Conclusions

1. Fractures in the Barnett shale grow in a complex network.
2. The cumulative fracture-network length, combining both hydraulic and natural fractures, resulting in maximum reservoir connectivity—not conventional-fracture half-lengths—controls gas recovery and drainage patterns.
3. Fracture growth in the Barnett shale can be approximately modeled by history matching recorded fracture data within a calibrated fracture model.
4. Fractures can be propagated simultaneously in the upper and lower Barnett during the same fracture treatment.
5. Fracture geometry is relatively predictable; however, fracture-network development is highly variable.

Acknowledgment

The authors would like to thank the management of Devon Energy for allowing publication of this data.

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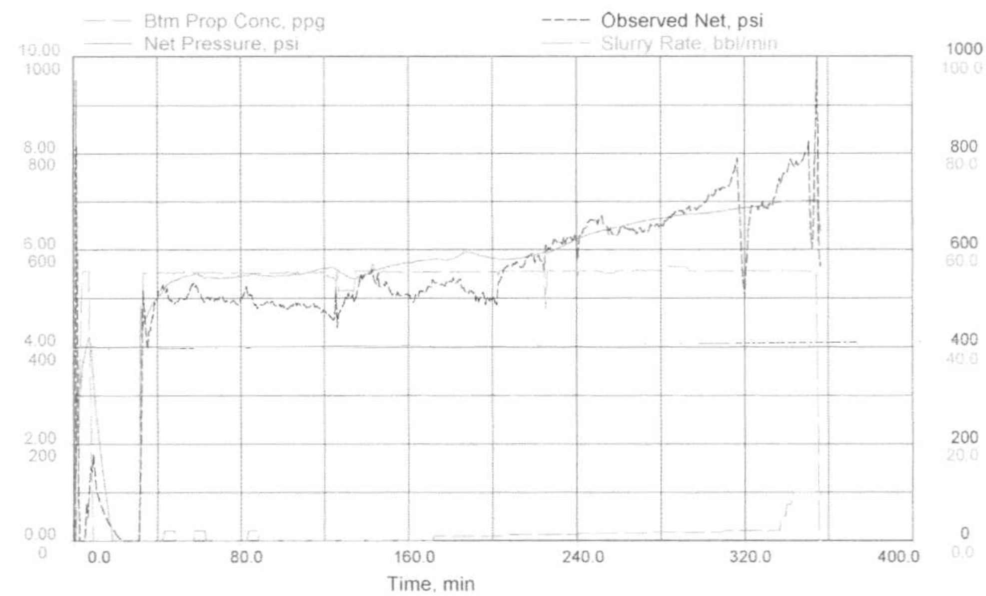

Fig. 12—Net-pressure match from lower Barnett treatment.

TABLE 3—FINAL CALIBRATED SETTING WITH NET-PRESSURE HISTORY MATCHING OF FRACTURE-MODEL RESULTS VS. MAPPED RESULTS FOR INDIVIDUAL- AND COMBO-FRACTURE TREATMENTS

	Composite Mapped		Model			
			Half-Length		Height	
Well	Height Wellbore, ft	Average Half-Length, ft	ft	Difference, %	ft	Difference, %
		Lower Barnett				
Well 1	415	2,600	2,585	0.58	320	23
Well 2	440	3,000	3,015	−0.50	330	25
Well 3	370	3,000	3,190	−6.33	320	14
Well 4 Refracture	325	2,500	2,480	0.80	335	−3
Well 5	380	2,090*	3,220	—	345	9
Lower Barnett Average	386	2,775	2,898	−1.36	330	15
		Upper Barnett**				
Well 1 (Upper)	480	3,300	3,260	1.21	700	−46
Well 1 (Lower)		920*	2,450	—		
Well 2 (Upper)	560	2,250	2,220	1.33	610	−9
Well 2 (Lower)		—	1,800	—		
Well 3 (Upper)	610	3,000	2,770	7.67	595	2
Well 3 (Lower)		—	1,850	—		
Well 4 (Upper)	460	650*	2,605	—	695	−51
Well 4 (Lower)		975*	2,100	—		
Well 5 (Upper)	475	1,290*	2,355	—	655	−38
Well 5 (Lower)		1,290*	1,575	—		
Upper Barnett Average	494	2,850	2,642	3.40	651	−32
Lower Barnett Average		—	1,955	—		
		Combo Fracs				
Well 6 (Upper)	780	2,480	2,450	1.21	460	41
Well 6 (Lower)		2,440	2,450	−0.41		
Well 7 (Upper)	560	1,335*	1,740	—	535	4
Well 7 (Lower)		—	1,100	—		
Well 8 (Upper)	570	1,420	1,480	−4.23	678	−19
Well 8 (Lower)		1,520	1,520	0.00		
Well 9 (Upper)	580	2,800	2,740	2.14	615	−6
Well 9 (Lower)		2,000	1,990	.50		
Well 10 (Upper)	450	2,845	2,820	.88	620	−38
Well 10 (Lower)		2,240	2,065	7.81		
Well 11 (Upper)	560	2,410	2,585	−7.26	575	−3
Well 11 (Lower)		2,420	2,420	0.00		
Lower Combo Average	583	2,391	2,303	−1.45	581	0
Upper Combo Average		2,124	1,924	1.58		

Asymmetrical fracture based on DHT data.
*Microseismic data used for half-length when no DHT available. Not included in the average.
**Upper Barnett fractures generally broke into lower Barnett.

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SI Metric Conversion Factors

bbl × 1.589 873	E–01	= m^3
ft × 3.048*	E–01	= m
ft^3 × 2.831 685	E–02	= m^3
gal × 3.785 412	E–03	= m^3
lbm × 4.535 924	E–01	= kg

*Conversion factor is exact.

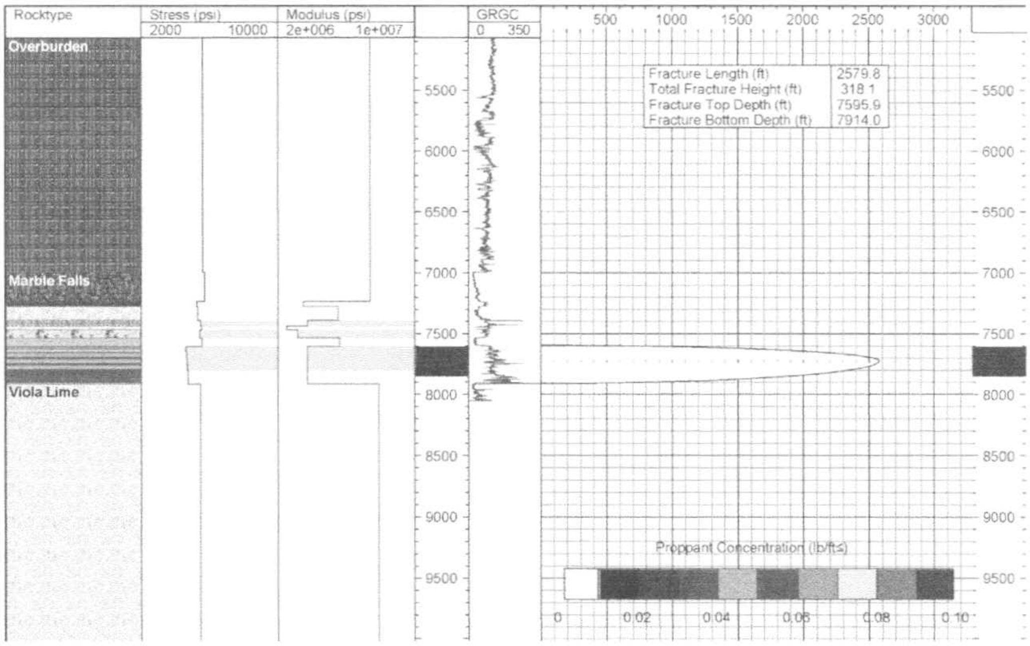

Fig. 13—3D-fracture-model output using measured fracture dimensions and treatment parameters and net-pressure matching to develop calibrated (and proprietary to Devon) model settings.

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SPE 110679

Improving Well Productivity and Profitability in the Bakken—A Summary of Our Experiences Drilling, Stimulating, and Operating Horizontal Wells

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This paper was prepared for presentation at the 2007 SPE Annual Technical Conference and Exhibition held in Anaheim, California, U.S.A., 11–14 November 2007.

Abstract

This case study will summarize the lessons learned during the stimulation and operation of horizontal laterals completed in the Middle Bakken formation of North Dakota and Montana. This paper will compare the production histories of these wells to offset wells completed with other techniques to evaluate best industry practices. Insight will be shared as to the effect of lateral length, wellbore azimuth and stimulation design on well production and overall well economics.

The Bakken formation of the Williston Basin is undergoing significant development in Manitoba, Saskatchewan, Montana, and North Dakota. Numerous operators are active in the area, with a wide variety of development approaches. The industry has not yet reached consensus on optimal drilling and stimulation strategies.

Results indicate significant progress in improving well production, while reducing the drilled lateral length and the treatment size. Efforts to improve diversion and optimize proppant type and size appear to provide more effective fracture treatments, while eliminating production problems related to the flowback of frac sand.

This paper will provide the following benefits to readers:

- Operators in the Bakken have experienced significant problems with flowback of frac sand, requiring frequent pump changes, conservative production strategies, and expensive cleanouts prior to restimulation. This paper will describe the steps taken to eliminate proppant flowback into the wellbore and the estimated economic impact.
- This paper will provide a case study comparing the production from wells completed with a variety of strategies.
- The results suggest many current laterals drilled in the Bakken are ineffectively stimulated and demonstrate that significant increases in well profitability are possible with more optimized treatments.
- Optimizing fracture treatment designs for horizontal wells requires an estimation of the fracture geometry – particularly a description of the intersection between the wellbore and the fracture. A fracture treatment designed under the assumption of a longitudinal frac will be entirely inadequate if the actual fracture propagates in a transverse orientation. This paper will describe our understanding of the fracture geometry and how that has affected treatment designs.

Introduction

The Middle Bakken play of the Williston Basin has generated significant interest, with over 45 companies completing wells in North Dakota and Montana and additional development activity accelerating in Canada (**Figure 1**).

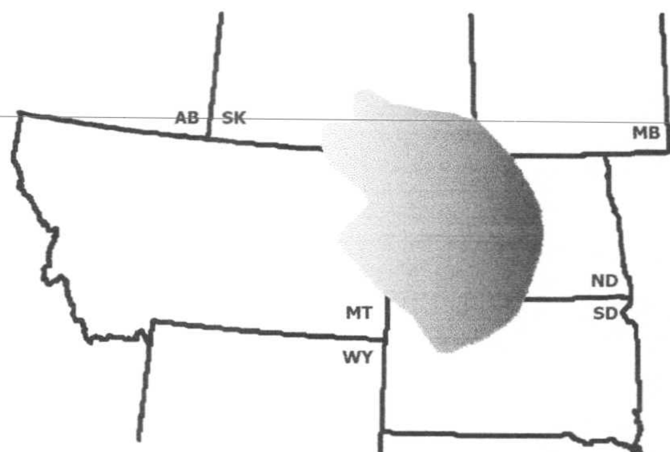

Figure 1 – Map of Williston Basin[1] (courtesy of Julie LeFever)

The Bakken formation comprises three members-- a lower and an upper shale, and a lithologically variable middle member which is the target of the current development. In North Dakota, this middle member typically consists of gray interbedded siltstones and sandstones and can reach 85 feet thick at depths of approximately 9,500 to 11,000 ft. Lesser

amounts of shale, dolostone, and limestone may also be present. In the Elm Coulee field of Montana, the Middle Bakken member thins to 6 to 15 feet thickness at a depth of approximately 10,000 feet and is generally categorized as a silty or sandy dolomite with significantly higher permeability.

The Bakken also extends beyond the Williston Basin into Saskatchewan and Manitoba, and has been formally recognized in Alberta and northern British Columbia. This study will focus solely on production from horizontal wells completed in the Middle Bakken within Montana and North Dakota.

Horizontal Well Completions

Most operators currently drill horizontal wells to develop the Middle Bakken, using a variety of wellbore configurations (**Figure 2**). In the most mature development in the Middle Bakken (the Elm Coulee Field in Montana), wells have been drilled on a density of approximately one well per section (640-acre spacing). While some operators favor single laterals, all wells in **Figure 2** were completed with multilaterals in coplanar or broadly spread lateral configurations.

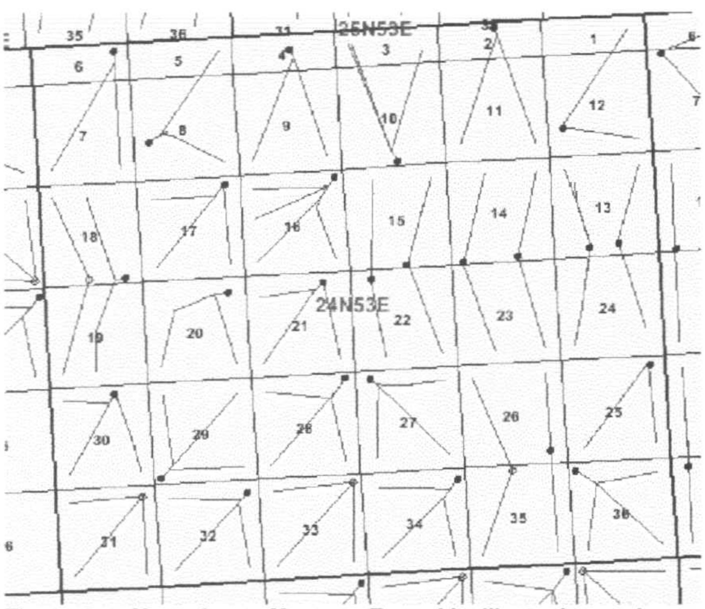

Figure 2 – Map of one Montana Township illustrating various wellbore Azimuths utilized in the Middle Bakken Development[2]

Although many multilateral wells have been stimulated simultaneously without any mechanical isolation, several techniques have been used to isolate laterals for individual stimulation. In Montana, the original wellbore is typically drilled horizontally in the Middle Bakken, and a window is milled uphole in the vertical section to kick off additional laterals. Subsequent laterals may not be cemented in place, simply placing an uncemented pre-drilled liner that is temporarily isolated with a tubing and packer assembly. However, this technique has posed some difficulties in North Dakota. Several operators have reported difficulty keeping fractures contained within the target Bakken horizon, and have observed radioactive tracer indicating vertical height growth into the shallower Lodgepole formation. In some cases, high H_2S or elevated watercut indicate fracs have propagated into shallower formations. Therefore, it is becoming more popular in North Dakota to kickoff additional laterals from the horizontal section to reduce the contact with shallower intervals.

Effectively isolating multiple laterals during the stimulation treatment is expensive and occasionally problematic. The authors have found a diminishing rate of return to drilling additional laterals and have elected to drill single laterals for most of the current completions. Although single, shorter laterals sacrifice reservoir contact, this strategy has reduced wellbore complexity, improved stimulation efficiency, and yielded higher returns on total well investment.

As suggested by **Figure 2**, laterals have been drilled in almost every conceivable azimuth across the Bakken development. However, wellbore azimuth can have a significant effect on the intersection between the wellbore and fracture (**Figure 3**). Fractures initiated from laterals aligned with the maximum horizontal stress would be expected to propagate along the axis of the wellbore (longitudinal frac). On the other hand, wellbores not aligned with the maximum horizontal stress will result in transversely intersecting fractures. These intersecting fractures have been described in the literature as orthogonal, perpendicular, oblique, imperfectly aligned, or transverse. For the purposes of this paper, "transverse fractures" will be used to describe fractures in which the majority of the fracture has grown away from the axis of the wellbore.

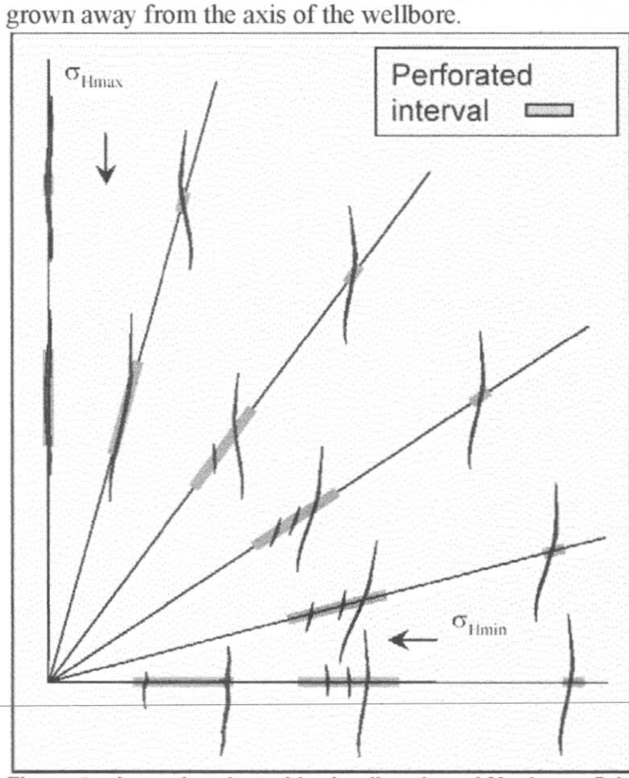

Figure 3 – Laterals oriented in the direction of Maximum Principle Stress should provide Longitudinal Fractures. All other orientations are expected to have Transversely Intersecting Fractures.[3]

Importance of Fracture Orientation upon Treatment Design

The extent of intersection between the wellbore and fracture greatly affects the optimization of fracture designs. In *vertical* wells, the industry typically expects a bi-wing fracture to grow from the well, thereby connecting all of the pay to the wellbore (**Figure 4**).

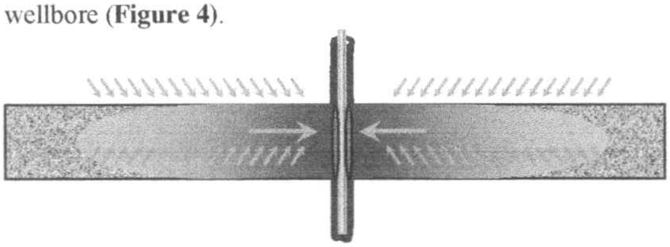

Figure 4 – Flow Convergence in Vertical Wells often results in High Fluid Velocity within Fractures

In an arbitrary formation with 50 feet of pay, the intersection between a *vertical* well and the two fracture wings would be 100 linear feet. If a fracture width on the order of ¼ inches ($1/50^{th}$ of a foot) is optimistically assumed, the cross sectional area of flow within two frac wings is ~2 ft^2. However, fractures are very long features, often exceeding 500 ft. half-length (X_f). Assuming an X_f of 500 ft, this arbitrary frac is in direct contact with 100,000 ft^2 of reservoir rock (two frac wings, two fracture faces in contact with matrix.) Therefore if the entire fracture is productive, the superficial fluid velocity within the fracture near-wellbore must be 50,000 times greater than anywhere in the matrix. This flow convergence near-wellbore is what causes many fracs to appear conductivity-limited and may explain the remarkable number of fields where wider fracs and superior proppants have proven beneficial.[4,5] However, horizontal wells are subject to an entirely different flow regime.

Longitudinal Fracs – If this identical hydraulic fracture is propagated as a longitudinal fracture from an uncemented horizontal well, a very large area of intersection is created. The produced oil and gas only travels within the proppant pack for a short distance (perhaps half the pay height) and the large intersection allows very low fluid velocity (**Figure 5**). Presuming the fracture grows from the top and bottom of the borehole, the same modest fracture (500 ft. half-length or 1000 ft. total length) provides 2000 ft. of intersection between the wellbore and fracture, or a cross sectional area of ~40 ft^2. Therefore, the fluid velocity within the fracture would be "only" 2500 times the velocity within the matrix. For identical fractures delivering identical oil rates, the fluid within the longitudinal fracture must travel only 5% as fast to reach the uncemented lateral as compared to the vertical well. In this longitudinal frac, the proppant choice is relatively insignificant, and any efforts to improve conductivity could result in pouring money down a hole with minimal expected benefit. The proppant of choice in this completion style would likely be the cheapest frac sand available. No efforts to improve fluid cleanliness, on-site quality control, or sand quality would be expected to provide much benefit in this fracture orientation.

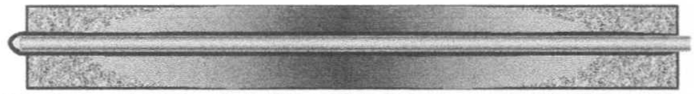

Figure 5 – Longitudinal Fracs with Uncemented Liners provide excellent communication between the Fracture and Wellbore

However, if a liner is cemented in place, the produced fluids must accelerate into limited perforation intervals (**Figure 6**). In this case, pressure losses within fractures may be a concern. When Lyco selected proppant for longitudinal fracs with *cemented* wellbores in the Middle Bakken, resin-coated sand was chosen to better accommodate flow convergence to limited perforation intervals.[6]

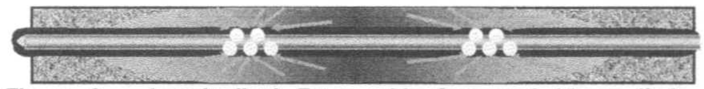

Figure 6 – Longitudinal Fracs with Cemented Liners limit communication between the Fracture and Wellbore. Flow Convergence may necessitate increases in Fracture Conductivity

Transverse Fracs – When the wellbore is oriented such that transverse fracs are created, an entirely different flow regime occurs. The intersection between a transverse frac and the wellbore may be limited to the circumference of the borehole (**Figure 7**). With an eight-inch diameter wellbore, the total intersection would be limited to two linear feet, or a meager 0.04 ft^2 cross-sectional area open to flow. In this scenario (assuming the 50 ft x 1000 ft transverse frac), the oil and gas near wellbore must achieve velocities over *2 million* times greater than in the reservoir matrix. In horizontal wells, transverse fracs will always be found to be choke points – any increases in fracture width or proppant quality should provide large increases in production.

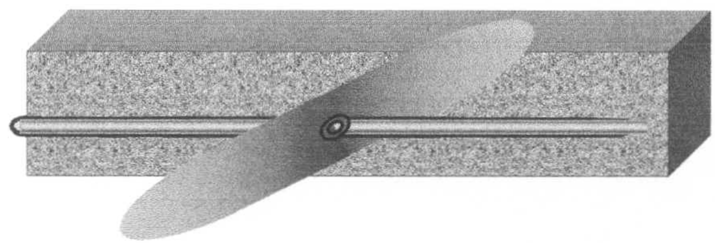

Figure 7 – Transverse Fracs provide an extremely small Intersection – the Circumference of the Wellbore

Therefore the industry has a dilemma:

- With longitudinal fracs, there is little reason to be concerned with proppant quality, fracture conductivity, onsite quality control, fluid cleanliness, or overdisplacing (overflushing) the proppant. There is such enormous intersection between the wellbore and the frac, that any conceivable damage to the conductivity is irrelevant. In theory, 100-mesh sand could provide an infinitely conductive frac, even after correcting for gel damage, cyclic stress, non-Darcy, multiphase flow and other damage factors.[7]
- However, with transverse fracs, *everything* matters. No commercially available proppant provides sufficient conductivity, and all efforts to improve fluid flow via wider fractures, cleaner fluids, better proppants, or superior implementation should provide increased rate.

In transverse fracs, it would be risky to overdisplace the proppant when using crosslinked fluids, as any loss of fracture width near-wellbore would further damage an already limiting pinch-point.

Therefore it is clear that a fracture design optimized for a transverse frac is entirely different than for a longitudinal frac. For this reason, it is critical to understand the fracture geometry in the Bakken.

Understanding Bakken Frac Geometry

The authors are aware that fractures have been mapped with downhole microseismic and/or surface tiltmeter technology from at least five wells in North Dakota and Montana. However, as of this date, very few of the results have been publicly disclosed by the operators owning the data.

Without the benefit of definitive fracture mapping, most operators are forced to assume orientations. Several operators have publicly stated that the difference between the horizontal principle stresses in the Middle Bakken is very low, and therefore they assume that fracs initiate axially and propagate longitudinally along the wellbore. Other operators rely on numerical models which describe the reservoir as a relatively simple, homogeneous structure – and thereby may also forecast simple longitudinal fracs.

However, there is significant evidence suggesting many Bakken fracs propagate in a transverse orientation, including:

- During two frac treatments, cross-linked sand-laden slurry was pumped into offset wells 2200 feet away in a transverse direction[6,8]. These events occurred *after* changes were made to wellbore azimuth and completion strategy designed to minimize transverse frac growth.
- Two additional service companies confirmed they have seen slurry pumped to surface in offset wells located over 1500 feet away in the transverse direction, but had not obtained permission to disclose the well name or specific details.
- It is not uncommon to see a temporary increase in watercut in offset wells following a stimulation treatment – suggesting significant fracture growth in a transverse direction.
- Treating pressure records often suggest transverse fracture growth. High net pressures often exceed both principle horizontal stresses, which is suggestive of complex fracturing.
- Radioactive tracer often shows only a small portion of the lateral is treated. Interpretation requires the presence of large transverse fractures in some wells. While it is also true that tracer surveys in the Bakken frequently show essentially full coverage of the lateral, that observation typically accompanies uncemented liners and could alternatively be attributed to entry of tracer into the liner-borehole annulus and therefore doesn't provide definitive proof of longitudinal fracs.

Fracture Orientation and Fracture Optimization in other Fields Developed With Horizontal Wellbores

A leading fracture mapping company shared some compiled conclusions from an extensive database of fractures mapped from horizontal wells, both with microseismic and surface tilt meter technology. As of April 2006, this company had used microseismic technology to map fracs in 140 horizontal wells in the United States and Canada. Those results showed:

- 5 to 10% of these treatments display predominantly longitudinal fracturing
- 90 to 95% show significant transverse components

There is some recognized bias in this dataset. Many operators in specific mapped fields will intentionally orient wellbores to maximize the likelihood of transverse fracs since field results have generally shown superior reservoir contact and increased productivity and recovery with multiple transverse fracs. Therefore the 90-95% frequency of transverse fracs is likely greater than would be achieved with random wellbore orientations.

A second dataset summarized the results from 175 treatments mapped from North American horizontal wells using tilt-meter technology. Again, this dataset does not include recent Bakken mapping results due to confidentiality. However, through April 2006, this second dataset summary showed:

- Approximately 15% of the treatments resulted in predominantly longitudinal fracs
- 75% to 80% of the fracs were predominantly transverse
- 5% to 10% of the treatments were mixed and difficult to classify.

Therefore, it is evident that transverse fracs are very frequently propagated from horizontal wells in North America.

Oil production through transverse fracs has been evaluated and modeled extensively by Olson[9,10,11] Haidar[12], Milton-Tayler, Norris[13] and others. Many local engineers dismiss the relevance of North Sea wells, as they are much more productive than the modest Bakken completions. However, the North Sea horizontal wells described in the references are typically completed with 7 or 8 very aggressive transverse fractures believed to achieve on the order of 8 to 10 lb/sq ft, providing fractures a full inch in width. On the flank developments, these treatments were initially producing on the order of 200 BOPD per frac through these very wide fracs (and lower oil velocity than in the much narrower Bakken fracs). When the operator began attempting increasingly aggressive tip screen out designs and increasing proppant diameter from 20/40 to 16/20 to 12/18 premium sieve Light Weight Ceramic (LWC), significant increases in production were observed just as predicted with sophisticated modeling (**Figure 8**).

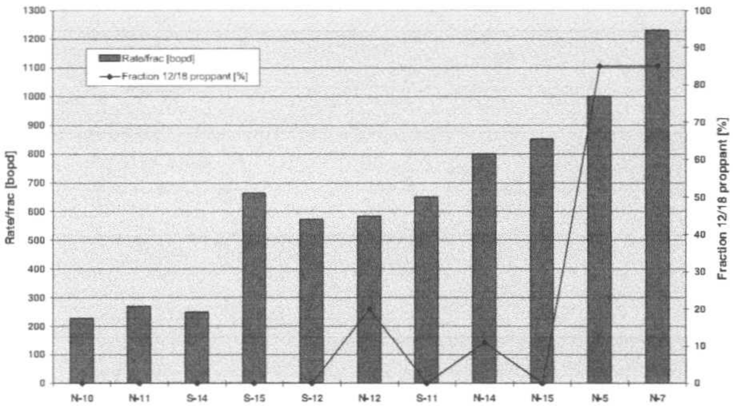

Figure 8 – Production from Transverse Fracs was Improved by increasing Conductivity with Wider Fracs and increased Proppant Conductivity[11]

It is recognized that the Bakken formation is not nearly as prolific as the Valhall formation – yet these field experiences validate that pressure losses in transverse fracs will restrict well production even at oil velocities lower than likely present in transverse Bakken fracs.

Although frac maps proving the orientation of Bakken fractures are not in hand, the majority of data available in the Bakken and in other horizontal well developments in North America indicate that many fractures propagate in a transverse direction. Therefore, emphasis was placed on improving conductivity in the Bakken fracture designs.

Resulting Frac Design Strategy

Many Bakken wells have been treated with over 1 million pounds of 40/70 or 20/40 frac sand in crosslinked fluid. If those fractures propagate in a transverse direction, the vast majority of that frac sand is likely wasted, since modeling suggests that the fracture length is far greater than the conductivity can support. The pressure losses in the near-wellbore region of the fracture are so immense due to flow convergence, that the created fracture length cannot possibly be effective.

Since it is believed that transverse fracs are frequently created, the authors' treatments have been designed to provide reduced fracture length, but with superior fracture conductivity. In addition, improved diversion techniques are believed to be beneficial to induce multiple transverse fracs.

Appendix A shows the author's current pumping schedule for a typical stimulation treatment. In summary, shorter laterals are drilled in a NW-SE orientation and stimulated with high concentrations of 16/20 LWC. Diversion is believed to be critical, and slugs of 16/20 LWC coated with a surface modification agent have been used between stages of uncoated proppant to encourage bridging and diversion. This design would need to be scaled up for operators attempting longer laterals or multiple lateral completions.

Refracs – Several papers have noted that refracture stimulation treatments have been successful in the Bakken, resulting in improved production and EUR.[6,14,15] A variety of theories have been proposed as to why the refracs are necessary:

- increased diversion, better lateral coverage
- refracture reorientation
- insufficient or inadequate initial fracture
- replacing lost conductivity caused by inadequate proppant strength
- replacing lost conductivity due to proppant flowback

Although the authors have successfully restimulated several Bakken laterals, not all attempts have been economically successful. If the fracturing process or initial pressure depletion from production allows superior placement of refracs, that is excellent justification to restimulate wells. However, it is more cost-effective to properly design and execute an initial frac than to plan on restimulating all wells due to any of the latter three reasons. Currently, radioactive tracers are incorporated in most of the authors' fracture designs. If subsequent logging or performance analyses suggest that only a small portion of the lateral has been stimulated, then additional isolation efforts and restimulation efforts have proven to be successful. However, in completions using ceramic proppant, the authors have not found it necessary to restimulate many wells as it appears there is minimal proppant degradation or flowback.

Continued Optimization

After seeing the positive results (presented later in this paper) with 20/40 ELWC, the designs were upgraded to a 16/20 premium sieve LWC for most treatments performed since May, 2006. This product provides the most uniform, spherical grains commercially available in a ceramic proppant and provides significantly higher conductivity under the expected conditions. This is the same substrate selected for use in the transverse fracs described in References 9-12, but does not require a resin coating in this application, since essentially zero proppant flowback has been observed when utilizing the uncoated 16/20 LWC. 12/18 and 8/12 mesh ceramic proppants that are commonly utilized with excellent results in Russian oil wells[16] have been considered and their performance may be evaluated in future Bakken completions.

Field Results

Proppant Flowback – One of the notable successes with this design strategy has been the virtual elimination of proppant flowback. Many operators in the Bakken report tremendous problems with production of frac sand, requiring frequent pump changes as the pumps are damaged by crushed frac sand. Stuck pumps are a common problem, resulting in strip jobs to recover the pump, rods, and tubing from the well. The cost to strip a well generally exceeds $35,000 plus the cost of lost/deferred production. A review of wells completed by three operators using ceramic proppant indicates zero pump failures due to crushed reservoir sand or proppant. Recent wells treated with uncoated ceramic proppant (without any additives or surface modification agents), have experienced zero proppant production problems. While the elimination of proppant flowback with spherical grains is surprising to some

operators, laboratory and theoretical work have previously documented[17,18,19] this effect.

Radioactive tracer followed by a tracer log is typically incorporated into the authors' frac designs to evaluate the proppant distribution along the lateral. Prior to the tracer survey, a cleanout is performed to remove proppant left in the wellbore during the stimulation treatment. On three occasions, wells were re-entered several years later in preparation for a refrac and only minor amounts of proppant were found in the horizontal lateral. This is in contrast to some operators who have been forced to cleanout massive quantities of frac sand before attempting refractures.

Oil Production as a Function of Proppant Type

Although the elimination of sand production often saves enough money to offset the incremental cost of ceramic proppant, a primary justification is the incremental well productivity observed.

<u>*North Dakota*</u> – Production and completion data were compiled for 157 Bakken wells in 8 counties, generally bounded by Ranges 90-105 and Townships 140-163 (**Figure 9**).

Figure 9 – Area of Development in North Dakota analyzed in this Study

Data for wells that were recompletions or re-entries of depleted Bakken intervals were removed from the dataset, yielding 151 wells. Production from treatments designed by the authors' companies were then compared to the statewide average (**Figure 10**). As the Bakken is an active play, there are many wells that have not yet achieved 28 months of production. Average production rates were calculated for each well by dividing the monthly cumulative production by the number of producing days. The averages at Month 1 shown in Figure 10 are based on 128 "Other" wells and 13 "Author" wells. At Month 12, the averages are based on 109 "Other" wells and 12 "Author" wells. At Month 22, the averages are based on 102 "Other" wells and only 3 "Author" wells which have been on production for this duration. This change in well population is the cause of the jump at month 22, as several lower rate wells have only been on production for 21 months.

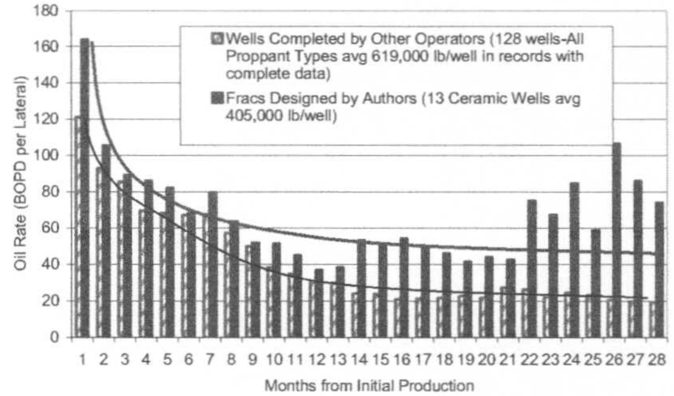

Figure 10 – Oil production for laterals stimulated by the Authors compared to Statewide Averages

Although these results appear to validate the design strategy, it was necessary to further examine the results to understand the influence of engineering design and local variation in reservoir quality. Well files obtained from the State of North Dakota website were reviewed for all wells. Although the proppant type is reported for many wells, the public database was enhanced by incorporating the proppant delivery records from one ceramic proppant manufacturer. This review identified ten additional wells completed with ceramic by seven additional operators. Although these ceramic completions were not as productive as the initial thirteen, inclusion of these wells increased the ceramic population to 23 wells, increasing the statistical confidence. The sand category includes 91 wells completed by 20 operators. Thirty seven wells could not be included in the above categories for the following reasons:

- Proppant type not reported; incomplete records
- Production not yet posted to website (new well)
- Well not stimulated due to mechanical problems
- Both ceramic and sand utilized in treatments

Figure 11 shows the production from these categories. Of the wells excluded because the proppant type was not reported to the State, it is believed the vast majority utilized frac sand, based on the operators' typical completion strategies, and review of one ceramic proppant supplier's delivery records. Inclusion of these wells in the sand category would further depress the average production from sand completions.

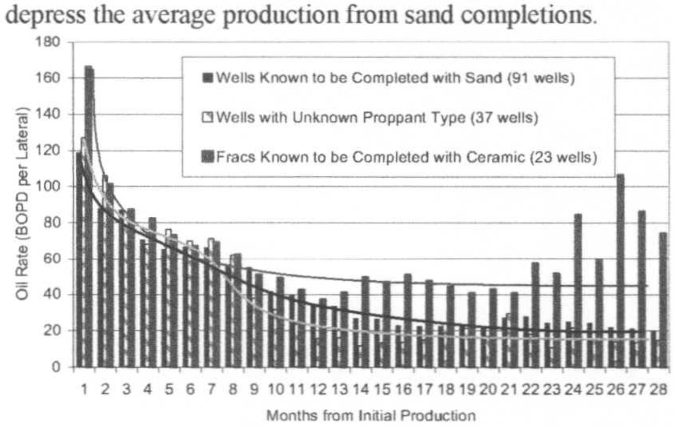

Figure 11 – Oil production for laterals in North Dakota as a function of Proppant Type.

Since only six of the 23 ceramic wells have been on-line for 22 months, there remains uncertainty regarding the long term performance of Bakken wells. However Figure 11 suggests that greater long-term production is provided by the ceramic completions. **Figure 12** shows the cumulative production reported to the State for these completions. The unusual flattening of the sand curve after 20 months is due to changes in well population, as some of the recent tri-lateral sand wells utilizing 1 million pounds of frac sand have provided improved initial production rates, but have not been on-line long enough to affect production rates beyond 20 months, which is increasingly dominated by older, lower productivity sand wells.

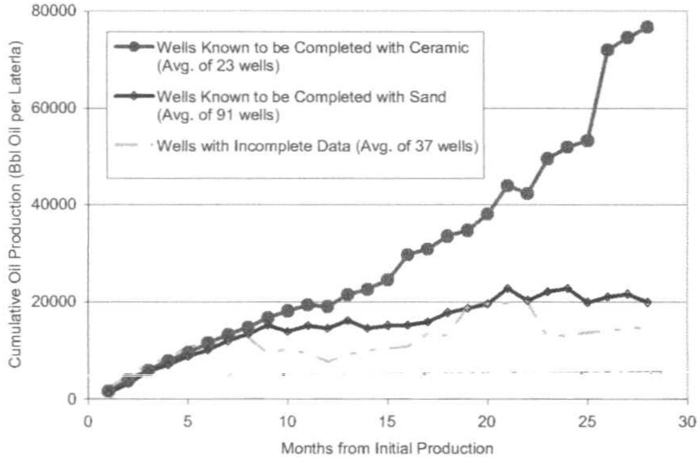

Figure 12 – Average cumulative Oil Production *per lateral* for Sand, Ceramic, and Unknown Completions in North Dakota

Instead of dividing well production by the number of drilled laterals, it is also interesting to view the total well rate disregarding the well configuration (**Figure 13**). Using the same production data normalized by well instead of by lateral, many of the wells with incomplete data are found to be relatively productive, but are multi-lateral completions.

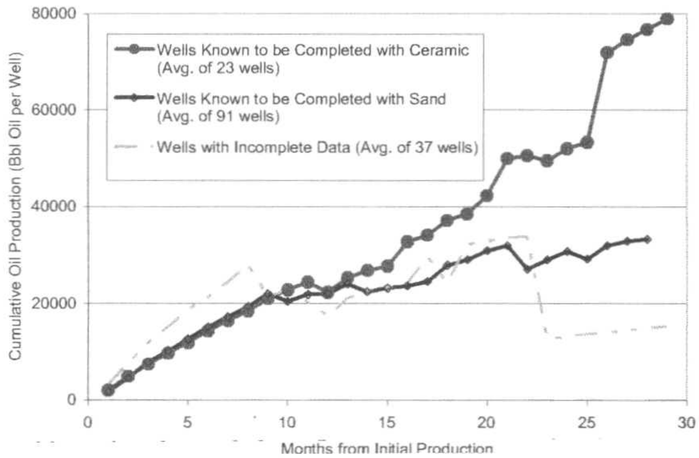

Figure 13 – Average cumulative Oil Production *per well* for Sand, Ceramic, and Unknown Completions in North Dakota

Geological Variation

While these state-wide trends suggest fracture conductivity affects production (evidence of transverse fracs), it is important to examine the results in smaller regions to ensure that the results are not skewed by the use of ceramic proppant in a "sweet spot". This review indicates that there are nine townships in North Dakota in which both ceramic and sand have been utilized. While the full comparison is too cumbersome to report here, in only three of these nine townships does the average sand treatment provide greater long term production than the average ceramic treatment. This is in spite of smaller average treatment sizes with ceramic proppant (statewide, 23 ceramic wells averaged 441,671 lb/well or 338,615 lb/lateral, while 91 sand wells averaged 630,219 lb/well or 360,691 lb/lateral). **In six of nine North Dakota townships with both proppant types used in offset wells, ceramic laterals are providing substantially higher production.**

This is not meant to imply that ceramic proppant is a magic bullet. The averages include four wells stimulated with ceramic proppant which produced less than 25 BOPD six months after initial production. Sustained production requires adequate reservoir quality, treatment design and execution.

Slickwater Fracturing – One operator has recently published[14] the first 30 days of production data for slickwater and cross-linked gel treatments in the North Dakota Bakken. Details of treatment size, lateral length, and stimulation cost are provided in the reference. The authors have utilized public data sources to track the continued production of those wells (**Figure 14**). Square symbols represent monthly production rates per lateral for nine wells treated with crosslinked fluids and 20/40 ELWC, denoted by XL1 through XL9 in SPE 108045. A single well received a slickwater stimulation with 30/50 ELWC (denoted as LV2 with an asterisk symbol) and four wells were treated with 40/70 Ottawa sand in slickwater, represented by circles and LV denoting low viscosity. The nine wells treated with 20/40 ELWC in cross-linked fluids have averaged over 50% higher production than slickwater treatments with 40/70 sand. Furthermore, the single well treated with 30/50 ELWC and slickwater has outperformed all types of wells. One wouldn't expect higher conductivity proppant to benefit a longitudinal frac. These results further suggest that these fracs may have developed some transverse component.

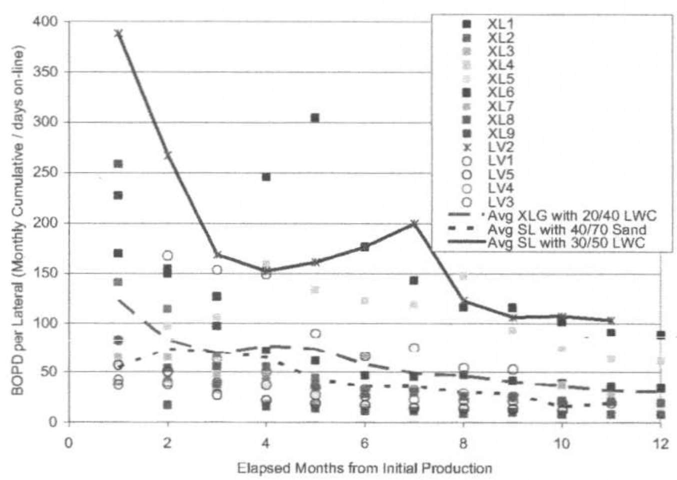

Figure 14 – Cross-linked treatments with 20/40 ELWC averaged approximately 50% higher production during the first 11 months compared to slickwater fracs with 40/70 sand. However one slickwater treatment with 30/50 ELWC has been outstanding.

The performance of the slickwater treatment with 30/50 ELWC was obviously intriguing. **Figure 15** shows a map presentation of this and nearby wells in the Capa Field. The well denoted as LV2 in Figure 14 is the Ferguson Smith 1-30H in Figure 15.

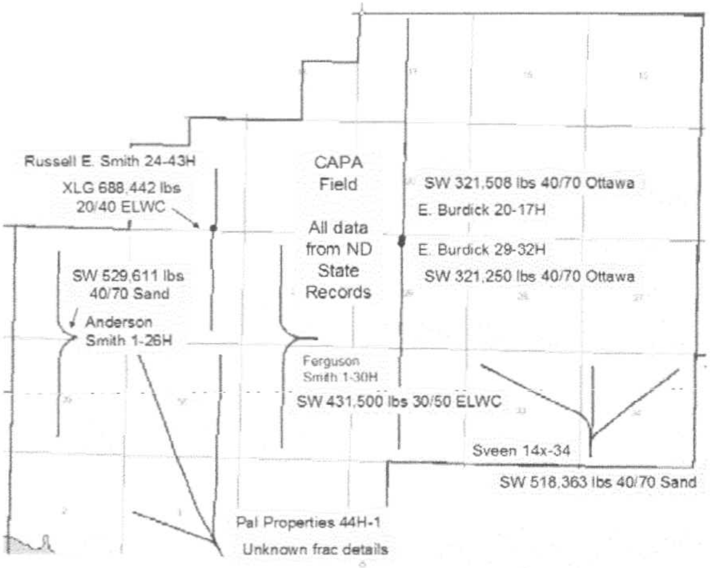

Figure 15 – Orientation and Treatment Data for Horizontal Bakken wells in the Capa Field. All data from public sources.

The total production from these wells is shown in **Figure 16**. In this figure, the rate has not been normalized by the number of laterals. From public sources, there are inadequate data to correct all production for fracture dates and pumping conditions. For instance, the Ferguson Smith well was stimulated prior to production, while the Russell Smith well was produced prior to stimulation. Regardless, it is apparent that wells in this area are providing excellent production (by North Dakota Bakken standards), and that slickwater fracs are a viable alternative in this field. It also appears that the two wells known to have been stimulated with ceramic proppants (one with slickwater, one with crosslinked gel) appear to provide superior sustained production compared to wells treated with sand or unknown proppant type. While completion decisions clearly should not be based on an isolated study of these seven wells, this comparison largely corroborates the understanding that conductivity is important in the Bakken completions. Again this finding suggests that frac growth is not solely limited to longitudinal orientation.

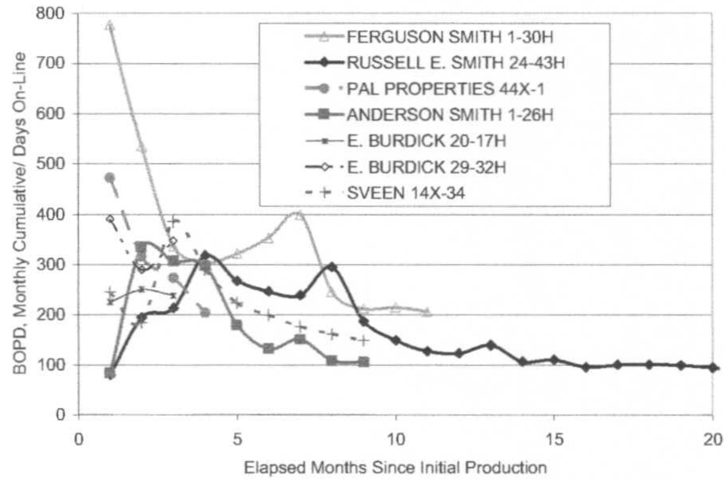

Figure 16 – Total Well Production for Wells shown in Figure 15. The two ceramic wells are Ferguson Smith 1-30H and Russell E. Smith 24-43H.

Overall, the analyses of North Dakota completions suggest that higher production rates have been obtained with wells using ceramic proppant, despite smaller frac treatments. These results validate the authors' impression that transverse fracs are created in some wells.

In ***Montana***, production results have been tabulated from the State records for 509 horizontal wells in the Elm Coulee Field. This field is located within Richland County **(Figure 17)** and is generally bounded by Townships 21N to 27N and Ranges 50E to 60E.

Figure 17 – Location of Elm Coulee Field in Richland County, Montana

The proppant type is not disclosed on the Montana website, therefore the author's 32 wells completed with higher conductivity ceramic proppant are compared to 477 wells of unknown proppant type. As shown in **Figure 18**, comparing the full results from Bakken wells across 34 townships, the author's completions do not appear to be as good as the field wide average. Figure 18 also distinguishes between wells completed with a broadly sieved ceramic and 16/20 and 20/40 ceramics.

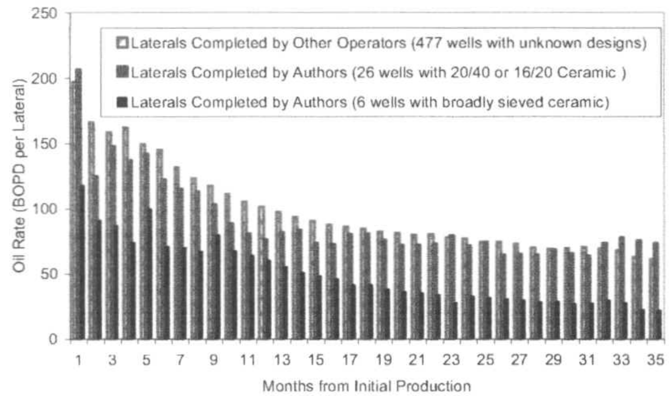

Figure 18 – Production Rate by Author's Laterals do not compare favorably to 477 wells in 34 Townships across the Elm Coulee Field.

Although Figure 18 does not show the same trend as the North Dakota results, the Montana analysis may be skewed by reservoir quality variation across the 34 townships (over 750,000 acres) these results represent. It is well known that reservoir quality varies throughout the Bakken. In Montana, the author's wells are concentrated in seven townships. **Figure 19** indicates that five of the author's townships are below average and two townships are above average.

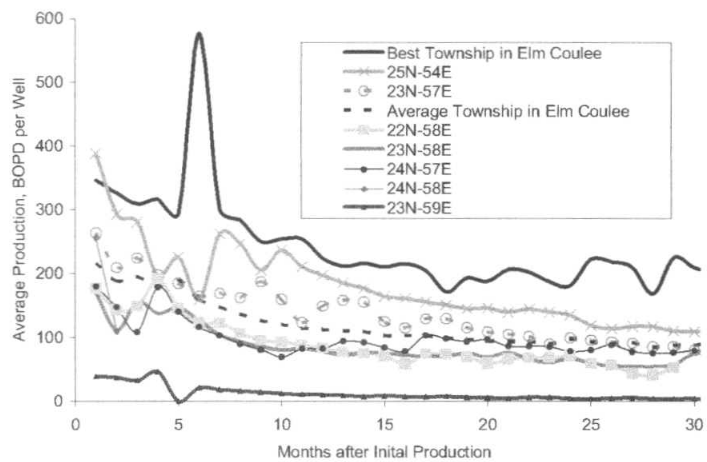

Figure 19 – Author's Wells are located in seven Townships- two are above the Montana Average and five are below Average.

Similar to the North Dakota analyses, the authors prefer to analyze results on a smaller geographical basis to reduce the effect of reservoir variation on outcome. **Figure 20** shows the area developed by wells drilled in Township 23N-57E. This township contains 45 Bakken wells -- 38 wells completed by seven different operators using unknown proppants plus seven wells completed by the authors denoted by a star.

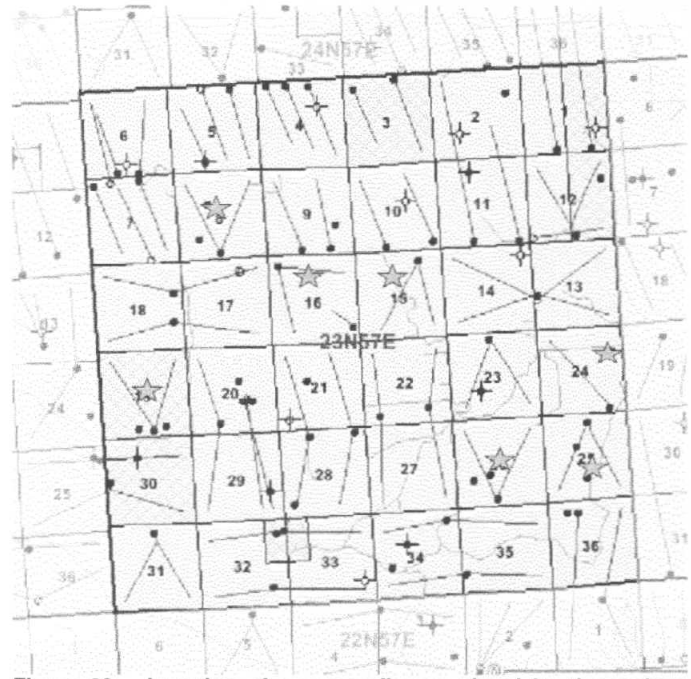

Figure 20 – Location of seven wells completed by the authors (denoted by stars) compared to 38 offset wells completed by seven different operators.

Figure 21 compares the production from wells in Township 23N-57E. Although initial rates were over 85 bopd higher for laterals stimulated with ceramic, when evaluated over three years, the incremental production is approximately 10 bopd for the proppants currently utilized by this operator.

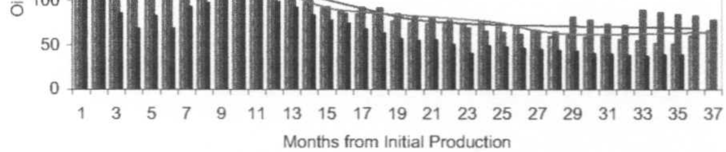

Figure 21 – Incremental production averaged 10 bopd for each lateral stimulated with 20/40 or 16/20 ceramic.

Only five of the seven townships have offset wells developed by other operators, and only 1 to 3 ceramic completions are available for comparison in two townships. However, based on these very sparse data, it appears ceramic completions are exceeding production from offset wells in Montana, but not by as large a margin as observed in North Dakota. A more detailed review of Montana results will require investigation of the proppant type and mass utilized in each treatment (which is not currently available on the Montana website).

Although the North Dakota and Montana field results suggest that high quality proppants are increasing Bakken production, a correct proppant selection cannot be made without an economic evaluation.

Value Comparison – Bakken wells in general are expensive to drill and complete. Depending on well complexity, the number of laterals and other factors, Bakken wells frequently cost $4 million to $8 million each. Ceramic proppant is also expensive, with the authors normally paying 35-40 cents/lb incremental cost for a premium sieved LWC over the white sand typically utilized by other area operators. With treatment sizes ranging 250,000 to 350,000 lbs, the cost to upgrade to premium LWC is $100,000 to $150,000. Additionally, many waterfracs are pumped at very high rates of 80 to 120 barrels per minute, and require incremental charges for increased horsepower, water hauling and frac tanks.

While an increase in cost of $150,000 should not be taken lightly, the cost of a proppant upgrade increases the wellcost by 2% to 4%. Therefore, if superior proppant is expected to increase the productivity and ultimate recovery of these completions by more than 4%, it will improve overall well economics. As shown previously, field results indicate the investment in premium proppant has increased production by substantially more than 4%, thereby providing a higher rate of return than drilling the base well. This does not include the added benefit associated with the savings in proppant flowback problems encountered with frac sand.

Note that some operators place much larger stimulation treatments than the authors. While some have drilled enormously long, complex multi-lateral completions, stimulated with over 1 million pounds of sand at high pumping rates, there is insufficient information to evaluate the cost of those completions. If an operator chose to upgrade 1 million pounds of frac sand to ceramic, a well may need to demonstrate a 10% increase in productivity for the proppant to have the same incremental ROI (Return on Investment) as drilling additional wells. While the authors believe this is an achievable hurdle, it is not clear whether extremely large volumes of proppant are optimal if there is a likelihood of transverse fracture development. Instead, the authors have found it to be more economic to simplify the well design, drill shorter laterals, and place smaller fractures containing high conductivity proppant.

Payout Comparison – Using $150,000 as the incremental cost of ceramic proppant and $40/bbl effective wellhead oil price corrected for royalties, taxes, etc., it would require approximately 10 bopd incremental rate to payout the incremental cost in one year. The production data from North Dakota suggests the upgrade is far exceeding that hurdle, and in Montana, the 10 bopd appears to be reached.

EUR Comparison – Although the dataset is small, it appears that ceramic completions have a shallower decline rate and will produce higher ultimate reserves than sand completions.

Other Bakken Considerations

Slickwater Fracturing – The North Dakota discussion highlights some of the recent success with slickwater treatments in the Bakken. While the potential to reduce gel damage is intriguing, the authors have not adopted this strategy at this time. In addition to conductivity and diversion concerns, it appears that slickwater fracturing has resulted in excessive height growth in some wells due either to extremely large fluid volumes or high pumping rates. A number of slickwater treatments appear to have frac'd into the Madison formation based on high levels of H_2S and sometimes high watercut post-frac. This has not been observed with smaller cross-linked gel treatments contained within the Bakken. If operators continue to encounter high H_2S levels following waterfrac stimulation, it may necessitate corrosion resistant alloys be selected in tubulars, which will significantly impact well economics.

Overflushing – Some operators significantly overflush or overdisplace their treatments to reduce the flowback of frac sand. With slickwater treatments, this may pose little concern, as small overflush volumes are not expected to significantly erode near-wellbore settled banks. Even with crosslinked fluids, if the fractures are longitudinal with the wellbore, there would be little anticipated damage because sufficient intersection between the wellbore and fracture will remain. However, if fractures are transverse (as suspected by the authors), overdisplacing proppant carried in a cross-linked fluid may seriously compromise the wellbore to fracture connectivity. With ceramic proppants, the operators have observed no proppant flowback and therefore find no need to overflush treatments.

Aggressive Drawdown – Some operators are hesitant to "pull their wells hard" – as they experience significant sand production and/or loss of productivity. Some operators contend that the natural fissures in the reservoir can be permanently damaged by reducing the pressure too quickly. However, this phenomenon has not been observed when using ceramic proppant, and therefore the authors believe that a sudden collapse of well productivity could be attributed to the severe crushing of frac sand when the bottomhole pressure is reduced, thus requiring the lower strength proppants to support the full closure stress. There are insufficient data available to calculate the bottomhole pressure of other operator's wells, so it was not possible to normalize production data for drawdown in this study.

Frac Fluids – Some operators are utilizing oil based frac fluids. This study has not made any attempt to deduct the flowback of oil based load fluids from the reported oil volumes. However, one recent attempt to place 16/20 proppant prematurely screened out using oil based gels, and at this time it has not been determined whether it was due to the difficulties associated with maintaining desired fluid rheology with oil-based fluids. The author's ceramic wells in this study are all treated using water based frac fluids.

Long Laterals to Hold Acreage – While the author's strategy has been to drill laterals that can be efficiently fractured with currently economic techniques explained in this paper, some operators choose to drill longer laterals in an attempt to hold acreage. This is a separate consideration that was not evaluated here.

Wellbore Orientation – The authors have found superior production from wellbores oriented NW-SE. The authors believe this azimuth allows creation of multiple transverse fracs. While many of the wells analyzed in this paper have been multilateral completions, the author's current strategy is to drill single laterals generally oriented in the NW-SE orientation, treated with high conductivity transverse fracs. If an operator is *not* designing the fractures to accommodate flow convergence in transverse fracs, it is not certain that this same azimuth will be optimal.

Conclusions

1) Horizontal wells with **longitudinal** fractures have exceedingly low conductivity requirements – any efforts to place better proppant, cleaner fluids, on-site QC, etc. has minimal effect on production.
2) Horizontal wells with **transverse** fractures have exceedingly high conductivity requirements – any efforts to increase near wellbore conductivity with superior proppants, increased fracture widths, cleaner fluids should be rewarded with significant increases in well productivity.
3) Currently, no fracture mapping data in the Bakken is available for public review. However, based on treating records, offset well watercuts, radioactive tracer surveys and other modeling, many Bakken fractures appear to propagate in a transverse orientation to the wellbore.
4) It appears that shorter laterals propped with smaller fracs containing high quality proppant are producing at superior sustained production rates compared to conventional treatments using larger quantities of frac sand.
5) Superior long-term production from high quality ceramic wells has been observed, suggesting increased EUR with better proppant, and thus reinforcing the theory that transverse fracs are propagated from some Bakken laterals.
6) Restimulation treatments have been very successful for offset operators on wells which originally utilized frac sand. However, wells treated with more durable proppant have less proppant flow back and may have a reduced need for restimulation.
7) The authors have experienced zero pump failures caused by proppant flowback from wells stimulated with uncoated ceramic proppant. This presents a significant cost and downtime savings compared to some operator's experience with sand.
8) Based on the author's cost structure, it is more cost-effective to drill shorter horizontal wells with a simple architecture, and stimulate with high quality proppant. The reduced drilling and isolation expenses easily offset the incremental proppant cost, reducing total development cost, while yielding improved production and EUR even in areas with marginal reservoir quality.
9) It is recognized that geological variations across the Bakken will alter the completion strategy in specific locations. As additional production data become available more detailed localized studies should be conducted to further optimize completion designs.

Nomenclature

BOPD	Barrels of Oil per Day
ELWC	Economy Light Weight Ceramic
EUR	Expected Ultimate Recovery
ISP	Intermediate Strength Proppant (ceramic)
LWC	Light Weight Ceramic
Sand	Frac Sand, here premium White sand
σ_{max}	Maximum Principle Horizontal Stress
σ_{min}	Minimum Principle Horizontal Stress
X_f	Fracture Half-Length

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Appendix

Simplified Frac Design for a Single Short Lateral Designed for Transverse Fracs from a Horizontal Wellbore

Pumping rates vary based on lateral length/orientation/conditions/design. Typical rates 30 to 70 bpm

Water-based fluids, linear gel for flush, cross-linked gel for treatment

SMA denotes Surface Modification Agent

Stage	Fluid	Volume (gal)	Prop Conc (ppg)	Prop Type	Prop Total (lbs)
1	Pad	16,000	0		0
2	Shut-In	0	0		0
3	Pad	10,000	0		0
4	Shut-In	0	0		0
5	Pad	10,000	0		0
6	Proppant Laden Fluid 1#	5,000	1	16/20 LWC	5,000
7	Pad	10,000	0		0
8	Proppant Laden Fluid 1#	5,000	1	16/20 LWC	5,000
9	Pad	16,000	0		0
10	Proppant Laden Fluid 1-4 # ramp	20,000	2.5	16/20 LWC	50,000
11	Diverter 8# 16-20 +SMA + balls	2,000	8	16/20 LWC+SMA	16,000
12	Pad	8,000	0		0
13	Proppant Laden Fluid 1-4 # ramp	20,000	2.5	16/20 LWC+SMA	50,000
14	Diverter 8# 16-20 +SMA + balls	2,000	8		16,000
15	Pad	8,000	0		0
16	Proppant Laden Fluid 1-4 # ramp	20,000	2.5	16/20 LWC	50,000
17	Diverter 8# 16-20 +SMA + balls	2,000	8	16/20 LWC+SMA	16,000
18	Pad	18,000	0		0
19	Proppant Laden Fluid 1-4+ # ramp	20,000	3	16/20 LWC	60,000
20	Flush	as needed	0		0
	Totals	**192,000**			**268,000**

BC Oil & Gas COMMISSION

SAFETY ADVISORY
2010-03

May 20, 2010

COMMUNICATION DURING FRACTURE STIMULATION

A large kick [1] was recently taken on a well being horizontally drilled for unconventional gas production in the Montney formation. The kick was caused by a fracturing operation being conducted on an adjacent horizontal well. Fracture sand was circulated from the drilling wellbore, which was 670m from the wellbore undergoing the fracturing operation.

To date, the BC Oil and Gas Commission (Commission) is aware of 18 fracture communication incidents in B.C. and one in Western Alberta as follows:

- Five incidents of fracture stimulation resulting in communication with an adjacent well during drilling.
- Three incidents of drilling into a hydraulic fracture formed during a previous stimulation on an adjacent well and containing high pressure fluids.
- Ten incidents of fracture stimulations communicating into adjacent producing wells.
- One incident of fracture stimulation communication into an adjacent leg on the same well for a multi-lateral well.

To date, all kicks taken during drilling were successfully controlled through conventional drilling safety measures (e.g. circulation with kill mud and/or reduction of the invading fracture stimulation pressure through controlled venting). Large kicks resulted in volumes up to $80m^3$ of fluids produced to surface. Invading fluids have included water, carbon dioxide, nitrogen, sand, drilling mud, other stimulation fluids and small amounts of gas.

Fracture fluids introduced into producing wells result in suspended production, substantial remediation costs and pose a potential safety hazard.

Incidents have occurred in horizontal wells with separation distances between well bores ranging from 50m to 715m.

Fracture propagation via large scale hydraulic fracturing operations has proven difficult to predict. Existing planes of weakness in target formations may result in fracture lengths that exceed initial design expectations.

RECOMMENDATIONS

It is recommended that operators cooperate through notifications and monitoring of all drilling and completion operations where fracturing takes place within 1000m of well bores existing or currently being drilled.

Operators are reminded of Commission Information Letter # OGC 08-20 which addresses communication and coordination with other operators during drilling and work over operations.

Finally, the Commission notes that any communication between fracture operations and existing well bores or well bores being drilled must be reported immediately to the Commission via the incident reporting line at 1-800-663-3456.

Should you have any questions regarding this Safety Advisory, please contact:

Graham Currie
Corporate Affairs Division
BC Oil and Gas Commission
250.419.4420
Graham.Currie@gov.bc.ca

(1) A kick is an unintended entry of water, gas, oil, or other formation fluid into wellbore that is under control and can be circulated out. It occurs when the formation fluid is driven by a formation pressure that is greater than the pressure exerted on it by the column of drilling mud in the wellbore. If the formation fluid is not controlled a blowout may result.

United States General Accounting Office

GAO

Report to the Chairman, Environment, Energy, and Natural Resources Subcommittee, Committee on Government Operations, House of Representatives

July 1989

DRINKING WATER

Safeguards Are Not Preventing Contamination From Injected Oil and Gas Wastes

GAO/RCED-89-97

GAO

United States
General Accounting Office
Washington, D.C. 20548

Resources, Community, and
Economic Development Division

B-227690

July 5, 1989

The Honorable Mike Synar
Chairman, Environment, Energy,
and Natural Resources Subcommittee
Committee on Government Operations
House of Representatives

Dear Mr. Chairman:

As requested, we have reviewed how the Environmental Protection Agency (EPA) and states are regulating underground injection of wastes related to oil and gas production. Under the Safe Drinking Water Act, EPA established safeguards to protect underground sources of drinking water from improper injection of wastes.

As arranged with your office, unless you publicly announce its contents earlier, we will make this report available to other interested parties 30 days after the date of this letter. At that time, we will also send copies to other appropriate congressional committees; the Administrator, EPA; and the Director, Office of Management and Budget.

This work was performed under the direction of Richard L. Hembra, Director for Environmental Protection Issues. Other major contributors to this report are listed in appendix II.

Sincerely yours,

J. Dexter Peach
Assistant Comptroller General

Executive Summary

Purpose

About half the population of the United States depends on groundwater for its drinking water. To help protect these supplies from contamination, the Safe Drinking Water Act of 1974 requires the Environmental Protection Agency (EPA) and states to whom EPA has delegated authority to regulate the injection of industrial waste products into the ground below drinking water supplies.

At the request of the Chairman, Environment, Energy, and Natural Resources Subcommittee, House Committee on Government Operations, GAO has been examining EPA's underground injection control program. This report addresses the regulation of injection wells used in oil and gas production, focusing specifically on (1) whether evidence exists of drinking water contamination from these wells, and if so, the causes and actions taken to prevent similar occurrences and (2) the degree to which states have implemented program safeguards to protect against drinking water contamination.

Background

Through underground injection, wastes and other fluids are deposited in porous rock formations below drinking water sources. EPA's program, created in 1980, established five classes of injection wells. Those used during oil and gas operations are Class II wells; the other classes are used for various types of hazardous and nonhazardous waste disposal.

Class II injection wells are used to dispose of strongly saline water (brines) produced when oil and gas are extracted or for reinjecting these fluids into oil fields to enhance oil recovery. These brines contain high levels of chloride—up to four times more than seawater—and total dissolved solid levels up to 200 times greater than EPA's drinking water taste standard. Brines from Class II wells can enter drinking water supplies directly, through cracks and leaks in the well casing, or indirectly, through nearby wells, such as those once used for oil and gas production, that have ceased operating. If these abandoned wells are not properly plugged—that is, sealed off—and have cracked casings, they can serve as pathways for injected brines to enter drinking water. Because groundwater moves very slowly, any contaminants that enter it will remain concentrated for long periods of time, and cleanup, if it is technically feasible, can be prohibitively costly.

The United States has about 160,000 Class II injection wells located in 31 states. Under provisions of the Safe Drinking Water Act, EPA has delegated primacy, or primary authority to regulate underground injection,

to 21 of these states, with 84 percent of the Class II wells, while the remaining states have EPA-administered programs.

EPA did not issue regulations for primacy states to follow in developing their programs but issued less binding guidance documents, which specified a number of basic safeguards to protect against drinking water contamination. The guidance includes: (1) operator-conducted pressure tests to check for cracks and leaks in the wells before they receive a permit to begin operations and (2) pressure tests and reviews of well files for wells that were already operating under state programs before the federal program went into effect to make sure the wells had been properly constructed and were being properly operated.

While GAO's evaluation of contamination cases was nationwide, its evaluation of how safeguards have been implemented focused only on state-administered programs, under which most Class II wells are regulated. GAO analyzed, in late 1987 and early 1988, a randomly selected sample of Class II wells in four of the primacy states—Kansas, New Mexico, Oklahoma, and Texas—to determine the extent to which states implemented program safeguards. About two-thirds of the state-regulated Class II wells are located in these four states.

Results in Brief

Although the full extent is unknown, EPA is aware of 23 cases nationwide in which drinking water was contaminated by Class II wells. In many of these cases, improperly plugged oil and gas wells in the vicinity of injection wells served as the pathway for brines to reach drinking water. Although operators of wells that began operating after the program went into effect are required to search for and plug any improperly plugged wells in the immediate vicinity of their injection wells, this requirement does not apply to those Class II wells that were operating before the program. Injection wells already operating before the program accounted for nearly all of the cases in which contamination has occurred through migration into improperly plugged wells. Moreover, GAO estimates that at least 70 percent of its universe of Class II wells were already operating before the program and therefore have not been subject to the requirement to search and plug nearby improperly plugged wells.

Although the four state programs we analyzed require the safeguards that are currently part of EPA's program, some of these states are issuing permits to operate new Class II wells without evidence that pressure tests were conducted, and some have not finished reviewing files and pressure testing some of the existing wells. EPA and the states have

taken steps to address some of these problems, but the states still need better documentation before issuing permits.

Principal Findings

Drinking Water Contamination

The full extent to which Class II wells have caused drinking water contamination is unknown, largely because the method for detecting contamination—installing underground monitors—can itself create a conduit for contamination and is therefore not widely used. Among the 23 known contamination cases, most resulted from cracks in the injection wells or from injection directly into drinking water; these cases were discovered, for the most part, as a result of required pressure testing and file reviews. However, in more than a third of the known cases, drinking water became contaminated when injected brines traveled up into improperly plugged abandoned wells in the vicinity of the injection wells and entered drinking water through cracks in these old wells. Since all but one of these injection wells were already operating at the time the program took effect, searches for and plugging of improperly plugged wells in the vicinity of the injection wells were not required. Contamination was not discovered, for the most part, until water supplies became too salty to drink or crops were ruined.

In 1976, before beginning the program, EPA proposed requiring all operators to search for and plug any improperly plugged abandoned wells within a 1/4-mile radius of their injection wells. However, commenters objected to making all wells subject to this rule because of the high costs involved. EPA decided to exempt those wells already operating, reasoning that because of the proximity between new wells and existing wells, the searches undertaken in the 1/4-mile radius of new wells would eventually uncover and result in the plugging of all the old wells.

Since then, however, relatively few new injection wells have come into operation. As a result, less than a third of GAO's universe of wells has been subject to area-of-review requirements. On the basis of a survey of old oil and gas production records, EPA has estimated that there are approximately 1.2 million abandoned oil and gas wells in the United States, of which about 200,000 may not be properly plugged. Moreover, among the four states that GAO examined, state officials in all but New Mexico believe that the numbers of improperly plugged wells are increasing—the result of the current economic decline in the oil

industry. Although these four states have programs to plug these wells, Texas and Oklahoma officials said they now have more wells to be plugged than they can afford to pay for, and Kansas officials fear that with the increased numbers of wells reported each year, their plugging program may not be sufficient in the future.

Implementation of Program Safeguards

At the time of GAO's review of well files in late 1987 and early 1988, implementation of program safeguards in the four states reviewed was mixed. GAO found that the files of 41 percent (with a sampling error of ±14 percent) of the wells with permits contained no evidence that pressure tests had ever been performed, even though these tests are required before start-up and every 5 years thereafter. In three of the four states GAO reviewed, internal controls were not in place to ensure that all necessary documentation was on file.

States have also had mixed results in their reviews and tests of wells that were operating before the program took effect. About 32(±18) percent of the file reviews and 69(±16) percent of the pressure tests had been performed. Having completed an equivalent review prior to achieving primacy, New Mexico was considered to have met its file review requirements. In the three other states, officials said their reviews had been hampered by the large number of wells to review, incomplete information in the files, and insufficient staff and resources. With additional funds provided by EPA, the states now expect to complete their reviews in 1989 or 1990.

Recommendations

In order to better safeguard drinking water supplies from contamination from Class II wells, GAO recommends that the Administrator, EPA, take steps to help ensure that (1) EPA- and state-administered programs are revised to make existing as well as new wells subject to area-of-review requirements and because of the large number of reviews that would have to be conducted, areas with a high potential for contamination from improperly plugged wells should be reviewed first, and (2) state program agencies institute internal controls to ensure that all necessary documentation is obtained before they issue Class II permits.

Agency Comments

GAO discussed its findings with EPA officials and has included their comments where appropriate. However, as agreed, GAO did not obtain official agency comments on a draft of this report.

Contents

Figures

Abbreviations

DCI	data collection instrument
EPA	Environmental Protection Agency
FURS	Federal Underground Injection Control Reporting System
GAO	General Accounting Office
MIT	mechanical integrity test
UIC	underground injection control
USDW	underground source of drinking water

Introduction

About half the population of the United States depends on groundwater for its drinking water. To help protect these supplies from contamination, the Congress passed Part C of the Safe Drinking Water Act in 1974. This law requires the Environmental Protection Agency (EPA) to establish an underground injection control (UIC) program. Through this program, EPA, directly or through delegation to states, regulates the design, construction, and operation of underground injection wells, which inject wastes and other fluids below underground drinking water sources.

At the request of the Chairman, Environment, Energy, and Natural Resources Subcommittee, House Committee on Government Operations, we have been examining how EPA is managing the UIC program. In this report, we look at EPA and state management of that part of the program that regulates two-thirds of the underground injection wells, or the Class II wells used in oil and gas production to inject salt water either for enhanced recovery or for disposal purposes.

Nature of Groundwater

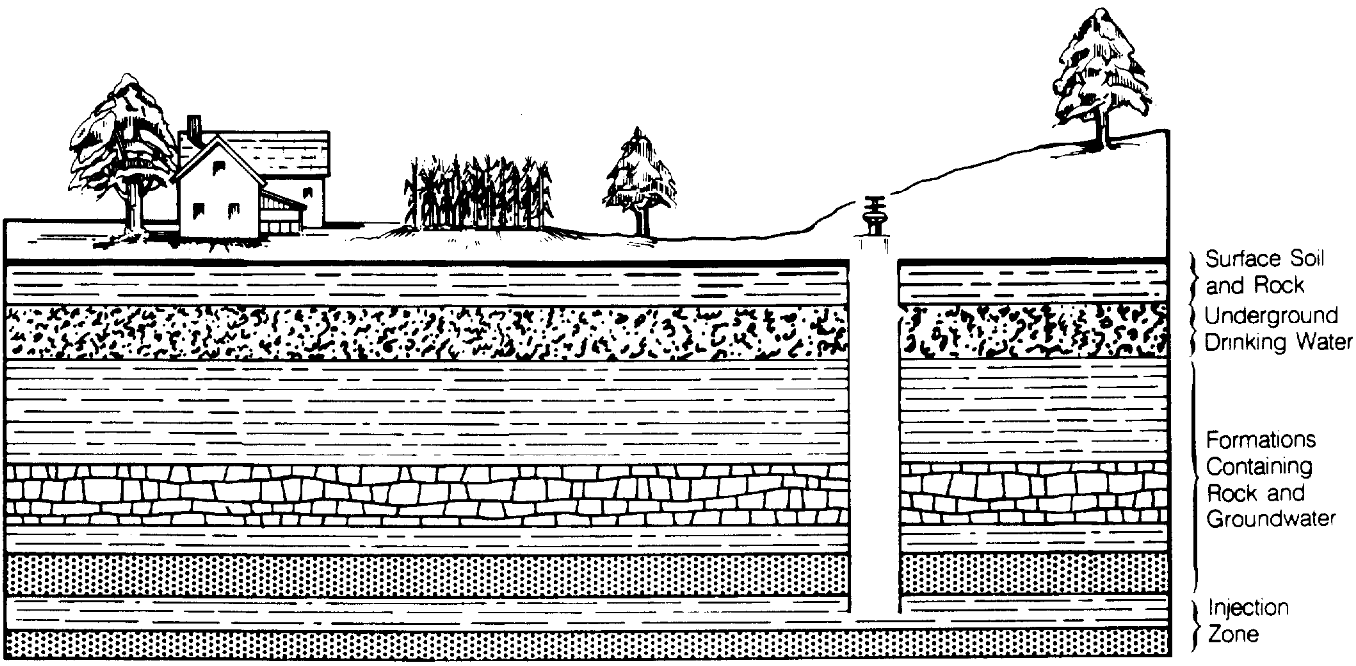
Groundwater is a vast resource that underlies the earth's surface. Within one-half mile of the surface of the United States, the volume of groundwater is estimated to be four times greater than that of the Great Lakes. Contained in layers of sand and rock called aquifers, groundwater can be located close to the surface or thousands of feet underneath.

For some parts of the country, groundwater is the sole or principal source of drinking water. Residents of 34 of the 100 largest cities in the United States rely on groundwater, as do about 95 percent of rural households. Because of this large dependency, groundwater contamination is a particular concern. Although it was once thought that natural filtration processes would change contaminants into harmless substances, groundwater contamination is being discovered with greater frequency and it is now recognized that the earth's cleansing capacity is limited.

Use of Injection Wells

Through underground injection, wastes and other fluids are deposited in porous rock formations, called injection zones, below drinking water sources. (See fig. 1.1.) Ideally, an injection zone is sealed above and below by unbroken, impermeable rock strata and is large enough to keep the injected fluids from reaching pressures great enough to fracture the confining rock layers.

Figure 1.1: Underground Injection



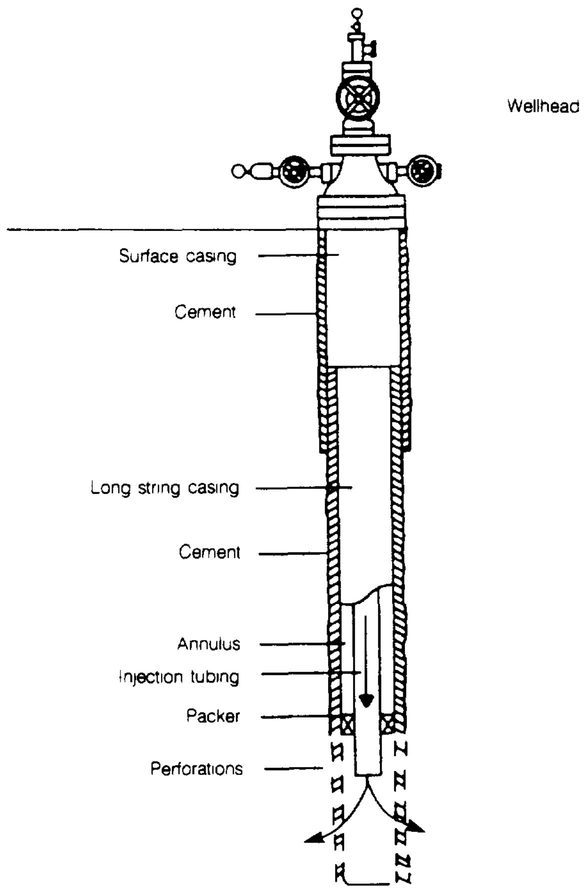
Source: GAO.

A modern injection well, shown in fig. 1.2, consists of three concentric pipes inserted into a well bore. The outermost casing is called the surface casing. This encloses the long string casing, which, in turn, contains the injection tubing. Fluids are injected through the injection tubing and enter the ground through perforations in the long string casing. To keep the injected fluids from entering the annulus, or the space between the tubing and the long string casing, the bottom is closed off by a packer.

Injection Wells in Oil and Gas Production

Although injection wells are used by other industries, particularly the chemical industry, they were first developed by the oil and gas industry and have been used for more than 50 years to dispose of salt water as well as to reinject it for production purposes. As oil and gas are extracted, strongly saline water, or brine, that occurs in underground rock formations flows up through production wells. In the early stages of production, very little brine is produced, but as oil and gas are removed, they are replaced by increasingly larger volumes of brine.

Figure 1.2: Modern Underground Injection Well



Source: Based on B. Klemt, et al., "Industrial Waste Disposal Wells: Mechanical Integrity, Proceedings of the International Symposium on Subsurface Injection of Liquid Wastes, New Orleans, Louisiana, 1986.

In the early part of this century, brines were disposed of in surface pits, but once the brines began to enter drinking water supplies, states banned this disposal practice. Oil producers then turned to underground injection for brine disposal. More recently, oil producers have used deep injection of brine for enhanced recovery of oil and gas, injecting it into oil-bearing formations to create the pressures necessary to force greater quantities of oil out of the ground. According to an American Petroleum Institute study, the domestic oil industry generated about 20.9 billion

barrels of brine in 1985, more than 5 barrels for each barrel of oil produced.

Brines associated with oil and gas production contain very high levels of chlorides and other dissolved solids. Chloride levels in brine can range from a few thousand parts per million (ppm) to over 150,000 ppm, as compared with seawater, which typically contains about 35,000 ppm of chlorides. Brines may also contain some amounts of petroleum hydrocarbons and additives, such as corrosion inhibitors, as well as radium and other radioactive materials. Altogether, brines generally contain about 30,000 to 100,000 milligrams of total dissolved solids per liter (mgl). By comparison, EPA's secondary drinking water standard (related to drinking water taste) calls for no more than 500 mgl total dissolved solids and it defines an underground source of drinking water as a water bearing formation containing less than 10,000 mgl of total dissolved solids.

Regulation of Underground Injection

Once contaminated, groundwater can be difficult and expensive to clean. Unlike rivers and streams, groundwater moves very slowly; therefore, contaminants remain concentrated for long periods of time. Cleansing an aquifer contaminated by brines could entail either pumping fresh water into it, to accelerate its flow into the body of water into which the aquifer normally discharges, or pumping the water out of the aquifer. If contamination is extensive, however, and covers a large area, rehabilitation may be extremely costly. In these cases, if the aquifer is left to cleanse itself, the process can take as long as 250 years.

Recognizing that cleanup was not always possible, Part C of the Safe Drinking Water Act of 1974 stressed prevention of contamination in order to ensure safe drinking water supplies. The act established a system of state and federal regulation of underground injection wells. EPA was to set standards for the design, construction, and operation of underground injection wells and establish a regulatory program to enforce those standards. However, EPA could delegate to the states primary regulatory authority, or primacy, if the states adopted federal minimum standards, or, in the case of oil and gas injection wells, if they could demonstrate to EPA that their existing programs prevented contamination of drinking water. In those states that chose not to assume primacy, or did not meet federal requirements, EPA assumed regulatory authority.

The UIC program created by EPA in 1980 established five classes of injection wells. Class I wells are used to dispose of hazardous waste and nonhazardous industrial and municipal waste below the deepest underground sources of drinking water. Class II wells are those used during oil and gas operations. Class III wells are used for special processes, such as mineral production. Class IV wells, which inject hazardous waste into or above underground sources of drinking water, are illegal and were required to be plugged by May 1985. Class V wells are all injection wells that do not fit into the other four classifications.

Oil and Gas Injection Wells

Of the approximately 253,000 active and temporarily inactive injection wells in the United States in 1987, the largest number—160,265—were Class II, oil and gas injection wells. These wells are located in 31 states, 21 of which have approved state programs, and on Indian lands. (See table 1.1.) These 21 states also contain 84 percent of the Class II injection wells. The 10 remaining states and Indian lands have EPA-administered regulatory programs.

Table 1.1: Class II Regulatory Programs

	Number of wells
State programs	
Alabama	206
Alaska	266
Arkansas	1,128
California	11,201
Colorado	932
Illinois	14,147
Kansas	14,009
Louisiana	4,212
Missouri	275
Nebraska	624
Nevada	8
New Mexico	3,913
North Dakota	595
Ohio	3,952
Oklahoma	22,579
Oregon	1
South Dakota	40
Texas	49,476
Utah	664
West Virginia	760
Wyoming	5,749
Total	**134,737**
EPA programs	
Arizona (including Indian lands)	413
Florida	77
Indiana	3,274
Kentucky	5,399
Michigan	1,631
Mississippi	936
Montana	1,449
New York	3,254
Osage Mineral Reserve (Oklahoma)	4,298
Pennsylvania	4,788
Tennessee	9
Total	**25,528**
Total	**160,265**

Under federal and state UIC programs, owners and operators of wells that began operating after the programs were established must obtain

permits in order to operate. The permits specify construction, operating, and reporting requirements, as well as procedures for monitoring the well and plugging it—that is, sealing it off—when it is no longer being used. Permit applications generally include information on the characteristics of both the well and the area in which it is to be located, including the location of nearby underground sources of drinking water and the composition of the injected fluid.

Although EPA initially expected that all Class II wells would have to obtain permits under the UIC program, states argued against this plan as impractical because of the large numbers of wells already operating under state programs that predated the federal program. They also pointed out that they already had on file much of the information that would be required in a permit application, such as injection pressure, design and construction specifications, and so on. EPA agreed, noting that a file review would be sufficient and would spare both the well operator and the states much of the costs involved in completing and reviewing permit applications.

EPA consequently allowed states that had regulatory programs to establish a combination of rule and permit procedures. Under this arrangement, those wells that were already operating when the states obtained primacy and already had permits issued by the state did not have to submit new permit applications but were authorized to continue to operate by rule. However, to verify that the well is not endangering underground sources of drinking water, the state had to review the files of these existing wells within 5 years after the state received primacy.

Under section 1425 of the Safe Drinking Water Act, EPA was authorized to delegate to states primary authority to regulate Class II injection wells as long as the states could demonstrate that they had programs that protected drinking water sources; states also had to have some form of inspection, monitoring, recordkeeping, and reporting requirements in their programs. Unlike the other UIC programs, EPA was not required by the act to establish specific regulatory standards that state Class II programs had to meet in order to obtain EPA's approval. Instead, EPA believed it was appropriate to issue more broadly worded guidance that would leave considerable discretion to the states on how to apply for primacy and to EPA regions on the criteria to be used in reviewing state programs.

Regarding state implementation of the program, the guidance outlines a number of basic safeguards that are not required but that EPA regards as

demonstration of a state program's ability to prevent drinking water contamination. In states with EPA-administered programs, these same safeguards are required by regulation with EPA regional offices acting as regulatory agencies.

- State programs are expected to require operators to conduct a mechanical integrity test before a well can begin operating, in the case of new wells, and at least every 5 years for all wells. These tests include pressure tests to check for cracks and leaks in the casing and reviews of construction records to establish the quality of the cement lining between the outer casing and the injection formation.
- The programs should also require well operators to submit reports at least annually that describe monthly average injection pressures and flow rates and volume. The reports are also to include the results of all mechanical integrity tests and an analysis of injected fluids if there have been major changes since the initial test.
- The authority issuing the permit must make periodic inspections of the wells to determine compliance and to verify the accuracy of information submitted.
- States are expected to require operators to properly plug their wells when they cease operating and maintain some form of financial responsibility for plugging.
- States must complete file reviews for wells that were permitted under a state program that predated the federal UIC program within 5 years after approval of their programs to make sure that these existing wells are properly constructed and operated.

Once it approves a state program, EPA remains responsible for making sure that the states are effectively regulating underground injection and withdrawing primacy if they are not. EPA's oversight activities consist of visiting the state agencies and evaluating their performance at least once a year and reviewing operator noncompliance reports prepared by the states quarterly. To assist the states in carrying out their Class II and other UIC programs, EPA provides grant funds according to a formula based on population, geographic area, and injection practices.

Objectives, Scope, and Methodology

Following the issuance of our earlier report on the Class I UIC program,[1] in August 1987, the Chairman, Environment, Energy, and Natural Resources Subcommittee, House Committee on Government Operations,

[1] Hazardous Waste: Controls Over Injection Well Disposal Operations, GAO/RCED-87-170, Aug. 28, 1987.

asked us to evaluate how EPA and the states are regulating underground injection related to oil and gas production. In subsequent discussions with his office, we agreed to examine

- whether evidence existed of contaminated drinking water as a result of underground injection of brines associated with oil and gas production, and if so, the causes of contamination and any actions taken to prevent similar cases from occurring in the future;
- how the states were regulating oil and gas underground injection wells; and
- the extent of states' efforts to properly plug all types of abandoned wells such as oil and gas wells that might serve as a pathway for injection fluids to reach drinking water.

To determine the extent of contamination across the country, we compiled EPA reports and other information obtained from state and EPA regional and headquarters officials in charge of UIC programs. From these sources, we identified known and suspected cases of contamination caused by Class II wells. We obtained additional information on each case and its disposition from officials of the responsible companies. For the contamination cases identified, we also obtained information on EPA and state officials' determinations of the causes of contamination. We traced the causes identified to state and EPA UIC program controls to determine whether controls existed to prevent similar cases of contamination from occurring in the future.

In contrast to our review of contamination, which was nationwide in scope, our review of state regulation of oil and gas injection wells focused only on state-administered programs and on their control mechanisms, including internal controls, for protecting drinking water. As agreed with the Chairman's office, we did not examine EPA-administered programs, since only 16 percent of Class II wells are in states with such programs. Among the 21 primacy states, we excluded Illinois because EPA conducted an extensive review of Illinois' program in 1986. Also, at the time of our review, Nevada had not yet been granted primacy.

From the 19 remaining states, we randomly selected four—Kansas, New Mexico, Oklahoma, and Texas—whose selection had a probability proportional to the total number of active and temporarily inactive wells in each state. Within these four states, we randomly selected a sample of active and temporarily inactive wells from EPA's inventory, known as the Federal Underground Injection Control Reporting System (FURS). For

our sample of active and temporarily inactive wells, we collected information on the extent to which UIC program safeguards were implemented by the states for both permitted and rule authorized wells.

Because of differences between the FURS inventory and state records, we were unable to fill out data collection instruments for about 27 percent of our sample. Our sample estimates, therefore, represent approximately 88,000 (± 10,400) active and temporarily inactive Class II wells for which we expect we could have obtained the required information. In this report, we refer to this as the number of Class II wells in our universe.

Sampling errors for specific estimates discussed in this report are stated at the 95-percent confidence level and are included in parentheses following the estimate. They may be presented in either of two ways, depending on the type of sampling error calculation used. With one type of calculation, for example, the sampling errors are presented as "23(±7) percent," which means that the chances are 19 out of 20 that the true value could be as low as 16 percent—23 minus 7—or as high as 30 percent—23 plus 7. For the other type of calculation, the range of values above and below the estimated values are different and the sampling errors are presented as "23 (15 to 32) percent." (See app. I for a more detailed description of our methodology.)

The information we collected on wells in our sample reflects the status of those wells at the end of 1987 and early 1988. In Oklahoma, we conducted our review of well records during October, November, and December 1987; in Kansas, our review took place during January and February 1988; and in New Mexico and Texas, we looked at well records during February and March 1988. The information came from records kept at state offices, including well authorization documents, well completion records, operators' quarterly reports, mechanical integrity test results, inspection reports, financial surety records, and reports on file reviews conducted by state regulatory authorities. Information on state activities, as well as information on EPA oversight of state activities, came from state UIC program staff and EPA officials in regions VI and VII, which oversee the four states we reviewed.

For our last objective, these same state officials, as well as field officials of state agencies, also gave us information on plugging programs and abandoned wells in their states.

We sought the views of EPA and state officials on the facts and findings discussed in this report and incorporated their comments where appropriate. In general, they agreed with the facts presented. However, as requested, we did not obtain official agency comments on a draft of this report from EPA or the states included in our review. We conducted our review in accordance with generally accepted government auditing standards between September 1987 and August 1988 and updated certain information through December 1988.

Injected Brines Can Continue to Contaminate Drinking Water

Because of possible underreporting by individuals whose drinking water was contaminated and difficulties in detection, the full extent to which injected brines have contaminated underground sources of drinking water is unknown. However, 23 cases of contamination have been confirmed and 4 are suspected.

In many of these cases, abandoned improperly plugged oil and gas wells—that is, wells that had ceased operating without having been properly sealed off—near an active injection well provided the path through which brines reached the aquifer. Although injection well operators seeking permits have to search for improperly plugged wells in the immediate vicinity of injection wells, this requirement does not apply to those injection wells already operating when states were delegated authority for the federal UIC program. Injection wells already operating comprise at least 70 percent of the estimated 88,000 Class II wells in our universe.

According to EPA, improperly plugged wells near operating injection wells present significant environmental problems. The agency has estimated that there may be about 1.2 million abandoned wells across the country, many of which may be improperly plugged, and, with one exception, the states we reviewed foresee the numbers growing as the oil industry remains in an economic slump. Each of the four states we visited use either special funds or general revenues to plug improperly plugged wells, but funding has not always been adequate, and many wells remain unplugged.

Drinking Water Contamination Caused by Class II Wells

On the basis of EPA's studies and information furnished by EPA and state agency officials, we identified 23 cases in which injected brines contaminated underground sources of drinking water (USDWS). These cases, listed in table 2.1, occurred in seven states: Kansas, Kentucky, Michigan, Mississippi, New Mexico, Oklahoma, and Texas. In all 23 cases, a USDW was contaminated, although the contamination may not have spread to sections of an aquifer that are actually used.

Table 2.1 also lists three cases in Mississippi and Montana in which brines were suspected of migrating from the injection zone, but no tests were performed to determine whether drinking water had become contaminated. In addition, table 2.1 lists one case in Oklahoma in which drinking water has been contaminated and Class II wells are suspected of causing the contamination.

Table 2.1: Known and Suspected Cases of Contamination From Class II Wells

Operator	Number of injection wells	Aquifers contaminated	Path for contamination
Martha Oil Field, Ashland Exploration Inc., Lawrence & Johnson Counties, Ky	601	Alluvium, Breathitt, & Lee	Improperly plugged and constructed wells.
Taffy Oil Field, CNB Corporation, Ohio County, Ky	102	Chapman Stray Sand	Improperly plugged wells.
Big Sinking Field, Charmane Oil Corp., Lee County, Ky	124	Big Lime	Improperly plugged wells.
Big Sinking Field, Hydrocarbon Inc., Lee County, Ky	46	Breathitt	Improperly plugged wells.
Big Sinking Field, L.P. Bretagne, Lee, Powell, Estill, and Wolfe Counties, Ky	29	Newman	Improperly plugged wells.
Irvine-Furness Field, Western Crude Reserves Inc., Powell & Estill Counties, Ky	115	Newman, Alluvium, Breathitt, & Lee	Improperly plugged wells.
Burrton Oil, Hollow-Nikkel Oil Field, Harvey and Reno Counties, Kans.	50–100	Equus Beds	Improperly plugged wells.
East Gladys Unit, Gulf Oil Company, Sedgwick County, Kans.	57	An alluvial deposit	Improperly plugged wells.
Yankee-Canyon Field, Cactus Operating Company, Tom Green County, Tex.	12–15	Leona and Bull Wagon	Improperly plugged wells.
Moore-Devonian Oil Field, Texaco U.S.A., Lea County, N. Mex.	1	Ogallala	Leaks in casing.
J. J. Hobgood Lease, Sun Exploration and Production Company, Hockley County, Tex.	1	Trinity Sands	Leaks in casing.
Madden-Davis Lease, Petro-Lewis Company, Graham County, Kans.	1	Alluvium near the South Soloman River	Leaks in casing.
Laketon Oil Field, Harris Oil Co., Muskegon County, Mich.	1	Surficial water table	Leaks in casing.
Albright Field, Kahn Operating Company, Noble County, Okla.	1	Warren	Leaks in casing.
North LaGrange Field, R&H Oil Corp., Adams County, Miss.	1	Wilcox	Injection into USDW.
T. K. Stanley, Inc., Wayne County, Miss.	2	Wilcox	Injection into USDW.

How and when detected	Effects	Remedial action
Discovered by U.S. Army Corps of Engineers in 1985.	Contaminated drinking water for 83 to 88 households.	No cleanup; judged technically infeasible. Ashland to plug 1,450 surrounding wells, monitor aquifer, and provide alternative water supplies. Ashland also fined $125,000 for violating the Safe Drinking Water Act.
Citizen compliant in 1985 of undrinkable water.	Damaged household water supplies.	No cleanup; judged too costly. Original owner filed for bankruptcy; EPA deciding whether or not to sue. EPA working with two new owners to identify wells needing to be plugged. EPA may have new owners install monitoring wells to measure progress of aquifer self-cleaning.
Citizen complaint in 1986 of undrinkable water.	Contamination of drinking water and stained clothes and porcelain.	No cleanup; judged too costly. EPA plans to fine company $125,000 and order it to provide alternative water supplies to citizens and plug or rework the wells in the field.
Citizen complaint in 1986.	Contamination of drinking water source.	No cleanup; judged too costly. EPA will not assess fine but will order wells to be plugged or reworked.
Discovered by EPA inspectors and monitoring wells in 1987.	Contamination of drinking water source.	No cleanup; judged too costly. EPA will not assess fine but will order wells to be plugged or reworked.
Citizen complaint in 1985 of undrinkable water.	Contaminated residential drinking water source.	Decision on cleanup pending. EPA will probably order company to provide alternative water supplies and plug or rework wells so as to prevent future contamination.
Citizen complaints began in 1943; a state task force confirmed in 1982.	Damaged major supply of drinking and irrigation water. People have to use bottled water and city has to relocate well.	State authorized $300 million to begin cleanup. All operating wells have passed mechanical integrity tests. All abandoned wells have been plugged.
Citizen discovered in 1970.	Farmer's wells and peach orchard were damaged.	No cleanup; judged too costly. Gulf Oil plugged wells judged to be the source of pollution. Farmer successfully sued Gulf for damages to crops.
Citizen complaint in early 1970s.	Contaminated water well.	No cleanup; judged too costly. Cactus Operating Company drilled a new water well for the citizen and plugged 30 wells in the field.
Citizen complaint in 1977.	Crops damaged. Farmer's property foreclosed.	No cleanup; judged too costly. The well has been reworked and is in compliance with UIC regulation. Farmer successfully sued Texaco for damages.
Sun pressure test in 1984.	Contaminated public drinking water and irrigation supplies.	Once Sun detected decline in pressure, it shut in well. Sun is voluntarily pumping aquifer and has installed monitoring wells to track cleanup.
Citizen complaint in 1981.	Irrigation well contaminated.	A majority of the contamination was cleaned up after Petro-Lewis pumped water into the aquifer. The well has been plugged.
Citizen complaint in 1980 of undrinkable water.	Contaminated drinking water.	Decision on cleanup pending. Michigan ordered Harris to submit cleanup proposal, but Harris has not yet done so. Harris reworked wells.
Citizen complaint in 1984.	Damaged soil and vegetation and polluted freshwater stream used by residents for domestic uses.	No cleanup; judged impractical. State ordered Kahn to plug well. Field has since shut down.
EPA reviews beginning in 1985.	None reported.	No cleanup; judged too costly. R&H fined $5,000 and ordered to rework its well to extend into a deeper injection zone.
EPA reviews beginning in 1985.	None reported.	No cleanup; judged too costly. T. K. Stanley told to rework well to extend into a deeper injection zone.

(continued)

Operator	Number of injection wells	Aquifers contaminated	Path for contamination
Flora Field, Belden & Blake Co., Madison County, Miss.	10	Wilcox	Injection into USDW.
Heidelberg Field, Fina Oil and Chemical Co., Jasper County, Miss.	1	Wilcox	Injection into USDW.
Overton Field, Oilwell Acquisition Co., Adams County, Miss.	1	Moody Branch	Injection into USDW.
Raleigh Field, Chevron Oil Co., Smith County, Miss.	2	Wilcox	Injection into USDW.
Board of Supervision Field, XMCO-Triad, Smith County, Miss.	1	Wilcox	Injection into USDW.
Summerland and South Central Fields, Triad Oil & Gas Company, Covington, Jones, and Smith Counties, Miss.	4	Wilcox	Injection into USDW.
Mize Field, Chevron USA, Inc., Ranking County, Miss.	1	Eutaw	Injection into USDW.
Suspected Cases			
Flat Coulee Field, Breck Operating Corporation Liberty County, Mont.	10	Eagle (Virgelle) Sandstone	Improperly plugged wells.
South Central Cut Bank Sand Unit, Unocal Company, Glacier County, Mont.	54	Two Medicine and Eagle	Improperly plugged wells.
Langsdale Field, Charles H. Moore Co., Clarke County, Miss.	6	Wilcox	Leaks in casing.
Prue Sand Unit, Sac and Fox Tribal Land, Lincoln County, Okla.	Unknown	Vamoosa	Improperly plugged wells.

How and when detected	Effects	Remedial action
EPA reviews beginning in 1985.	None reported.	No cleanup; judged too costly. Belden and Blake ordered to rework well to extend into a deeper injection zone.
EPA reviews beginning in 1985.	None reported.	No cleanup; judged too costly. Fina fined $75,000 for violating Safe Drinking Water Act and ordered to rework well to extend into a deeper injection zone.
EPA reviews beginning in 1985.	None reported.	No cleanup; judged too costly. Oilwell fined $4,000 for violating Safe Drinking Water Act and ordered to rework well to extend into a deeper injection zone.
EPA reviews beginning in 1985.	None reported.	No cleanup; judged too costly. Chevron ordered to rework well to extend into a deeper injection zone.
EPA reviews beginning in 1985.	None reported.	No cleanup; judged too costly. XMCO-Triad ordered to rework well to extend into a deeper injection zone.
EPA reviews beginning in 1985.	None reported.	No cleanup; judged too costly. Triad ordered to rework well to extend into a deeper injection zone.
EPA reviews beginning in 1985.	None reported.	No cleanup; judged too costly. Chevron ordered to rework well to extend into a deeper injection zone.
Citizen complaint in 1985 of purging wells.	None reported.	Owner plugged the abandoned well.
Citizen complaint in 1986 of purging wells.	Residence's backup water supply may be contaminated.	A production well that was flowing at the surface was plugged by the state.
Routine inspection and pressure test in 1988.	None reported.	State arranged for wells to be plugged.
Citizen complaint in 1977.	Contaminated drinking water.	The Department of the Interior is attempting to determine the party responsible for contamination.

There may be more instances of contamination because not all occurrences are detected nor are all known cases necessarily reported. According to EPA officials and a state official, individuals whose drinking water is affected may choose to deal directly with the well operator and never inform the regulatory authority.

Contamination is difficult to detect. As shown in table 2.1, about half the known and suspected cases were discovered only after contamination had become obvious to the people affected, for example, when their well water became too salty to drink, their crops were ruined, or when they could see water flowing at the surface of old wells. Neither EPA nor the states routinely require groundwater monitoring for Class II wells. Although monitoring wells can be used to measure the extent of contamination, they are of limited value for detecting contamination away from the well since they can only be used in a small area and are therefore not useful for assessing large aquifers. In addition, deep monitoring wells

themselves create potential routes by which contaminants can reach drinking water.

For the most part, the remaining cases were discovered by the operator or EPA staff during UIC program monitoring operations required to ensure that wells are being properly operated. Three were discovered during pressure tests, which revealed leaks in the casing or some other structural failure. The other nine cases, all in Mississippi, were discovered by EPA while reviewing injection records. From these records, EPA staff could determine that the wells, which were constructed before the UIC program went into effect, were injecting directly into a USDW. In all 12 of these cases, EPA or the state directed operators to cease injection until the wells were repaired or reworked.

In addition to the 23 cases of contamination that have been confirmed, 4 cases are also suspected. Two were reported to the state of Montana by residents who saw water flowing out of abandoned oil and gas production wells located near enhanced recovery wells. The state suspected that the pressure from these enhanced recovery operations was forcing fluids up through the unplugged production wells. Because of the possibility that these fluids could be entering drinking water supplies through leaks in the casing of the old wells, both wells were plugged. In Mississippi, the state arranged for wells that failed mechanical integrity tests because of numerous cracks in the casing to be plugged. In addition, on Indian lands in Oklahoma, the Department of the Interior is determining whether enhanced recovery wells or production wells are responsible for contaminated drinking water.

Causes and Consequences of Contamination

The 23 cases in which contamination was confirmed can be traced to three principal causes: five cases resulted from leaks in the casing of the injection wells, nine cases resulted from injection into the USDW, and nine resulted from migration of brines from operating injection wells into nearby oil and gas wells that had been left unplugged or improperly plugged.

Once contamination was discovered, regulatory authorities in either EPA regions or the states directed responsible companies to prevent further contamination by plugging their injection wells or the abandoned wells, reworking injection wells to repair cracked casings, or extending the wells below the USDW. Some companies were also directed to provide alternative drinking water supplies. In a few instances, property owners

sought and received court-awarded compensation for damages. According to an EPA official, although the Safe Drinking Water Act and EPA regulations do not require cleanups in every contamination case, EPA and the states can require cleanups. In three cases, cleanup efforts were undertaken and in two other cases, cleanup efforts are currently under consideration. In the other 18 cases, EPA or the state decided that cleanup was either technically not feasible, too expensive, or not practical because the aquifer was already high in brine content and not usable for drinking water without treatment.

The following case examples depict the circumstances under which contamination has occurred and the efforts to remedy it.

Contamination Through Leaks in Casing

Lea County, New Mexico

During the 1970s, 20 million gallons of salt water leaked from a Texaco disposal well in Lea County, New Mexico, into portions of a drinking water source, the Ogallala aquifer. Some of the brine made its way into a rancher's irrigation well, damaging his crop and, according to the rancher, ultimately causing the foreclosure of his farm property. On the basis of the results of a pressure test, the rancher successfully sued Texaco in 1977 for damages. Texaco subsequently made repairs to the well, and it is now operating in compliance with UIC regulations. Texaco was not required to clean the aquifer, however, because, according to the Chief of New Mexico's Environment Bureau, the cost could not be economically justified.

Hockley County, Texas

In 1984, the Sun Exploration and Production Company discovered that its disposal well in Hockley, Texas, was contaminating the Trinity Sands aquifer, which provides drinking water to parts of northern Texas and irrigation water to much of northern and central Texas. After Sun detected a decline in the pressure of its disposal well, it conducted a mechanical integrity test and found that the casing had ruptured. The company then notified state authorities and plugged the well. Sun also began taking water samples to determine the extent of the contamination, flushing the salt water from the aquifer, and installing monitoring wells to determine whether chloride levels were returning to acceptable levels. As of November 1988, monitoring showed that the chloride level

has been reduced but has not yet returned to the original level. State officials said that there have been no complaints about drinking water quality as a result of this episode.

Contamination Through Direct Injection Into the Aquifer

While reviewing the injection records of existing disposal wells in Mississippi beginning in 1985, EPA discovered that 23 wells in 9 different fields were injecting directly into a drinking water source. Since direct injection is prohibited by UIC regulations, EPA ordered the operators to cease injecting into the aquifer and to rework their wells so that they extend into a deeper injection zone. EPA also assessed penalties against the operators ranging from $4,000 to $75,000 for violating the Safe Drinking Water Act and from $100 to $1,000 a day for continued noncompliance, depending on the operator's history of compliance and other factors. EPA officials told us that the operators would not be required to perform any cleanup since there had been no complaints about the drinking water and the costs of cleanup could not be economically justified.

Contamination Through Abandoned Wells

Lawrence and Johnson Counties, Kentucky

In 1985, while constructing lakes in the area, the U.S. Army Corps of Engineers discovered that brine was contaminating Blaire Creek in Lawrence and Johnson Counties, Kentucky. After the Corps reported it, EPA traced the contamination to an Ashland Exploration Company field of 601 enhanced recovery wells. After sampling 20 water wells, EPA found that the drinking water for 83 to 88 households had become contaminated.

The Ashland field contained 1,450 abandoned oil and gas wells that had not been plugged, and brines had entered drinking water supplies through cracks in the casing of these wells. EPA therefore required Ashland to properly plug the abandoned wells, provide alternative water supplies to homeowners whose wells were contaminated, and install long-term monitoring devices to track the natural cleanup process. EPA also fined the company $125,000 for violating the Safe Drinking Water Act. Because of the extent of contamination, EPA officials decided it would not be technically feasible to clean up the aquifer. Drinking water supplies will consequently remain contaminated for perhaps another 20

years, according to the head of the UIC program in EPA region IV, until the affected aquifers can cleanse themselves.

Ohio County, Kentucky

Also in 1985, residents of Ohio County, Kentucky, complained to EPA that their drinking water had become contaminated. EPA traced the contamination to a CNB Corporation field of 102 enhanced recovery wells, known as the Taffy Oil Field. According to EPA's staff geologist in region IV, there were over 100 unplugged abandoned wells in the field. EPA reported that 62 injection wells failed mechanical integrity tests and lacked adequate casing and cementing. As a result, brines had entered the Chapman Stray Sand aquifer, which is a source of drinking water.

EPA's analysis of a sample of four water wells in the vicinity of the Taffy field revealed that one well had a total dissolved solid concentration above the maximum contaminant level—4.5 times the drinking water standard. EPA could not determine the concentration for one of the other wells because the resident's well contained oil so thick it coated EPA's measuring instrument. No contamination was found in the two remaining wells. Residents with contaminated drinking water wells had to obtain water from other sources, in some cases using pond water or installing cistern systems to collect rainwater.

An EPA official said CNB subsequently went bankrupt and lost its leases in the Taffy field. EPA and the new owners are now identifying wells that need to be plugged. Although EPA will not require cleanup because of its high costs, the agency is considering having the new owner install monitoring wells to track the natural cleanup process. EPA is also considering suing the original owner.

Safeguards Do Not Prevent Contamination by Abandoned Wells

Of the three causes of contamination, two—cracked casings and improper injection—were detected during the course of required pressure tests and record reviews for the most part. However, in only one case did these activities detect contamination through unplugged wells. While some states have special programs to plug abandoned wells, the number of improperly plugged abandoned wells, already estimated to be large, is growing, and some states are even now unable to pay for all the wells that need to be plugged.

Area-Of-Review Requirements

According to EPA guidance and state regulations (in the four states we reviewed), applicants for Class II permits must undertake a search for abandoned wells within at least a 1/4-mile radius of the injection well. The search is limited to wells of public record. Once these wells are identified, permit applicants must ensure that the abandoned wells are plugged in a manner that prevents the movement of brines into USDWS.

When EPA first proposed this so-called "area-of-review" requirement in 1976, it applied to both new injection wells and those that were operating when the UIC program went into effect. However, commenters objected to imposing this requirement because of the large costs involved. While noting that dangers to underground sources of drinking water would also be great if there were large numbers of wells that had to be plugged, EPA nevertheless decided to limit the area-of-review requirement to new wells only. The agency believed that since new wells would be constructed in or near old fields, the area reviews for these new wells would eventually identify most abandoned wells, albeit over a longer period of time than if existing wells also had to conduct area reviews. EPA stated, however, that its decision would be open to review and that after the first year of state program operation, EPA would examine information submitted by the states on the costs and benefits of conducting area reviews and consider whether to change its requirements.

After publishing these proposed regulations, an EPA consultant reported to the agency on the costs of complying with its proposal.[1] On the basis of estimates of the number of abandoned and producing wells in the United States, the consultant calculated the rate at which these wells would be reviewed. Assuming that 5,000 new injection wells would be added each year, the consultant estimated that it would take roughly 10 years before at least half the wells to be reviewed had been covered and over 20 years before nearly all the wells were reviewed. The consultant also estimated that most wells reviewed would not require any work but that 7.5 percent of all abandoned wells would have to be replugged, at an average cost of $20,000 per well.

Since EPA delegated regulatory authority to the states, they have issued permits to relatively few new wells. According to our projections, only 23(±7) percent, or about 20,300 out of the estimated 88,000 wells in our universe at the end of 1987, began operating after the UIC programs

[1]Cost of Compliance, Proposed Underground Injection Control Program, Oil and Gas Wells, prepared for Office of Drinking Water, EPA (June 1979).

were implemented. Consequently, the majority of Class II wells in our universe have not been subject to area-of-review requirements.

Although EPA did not conduct the anticipated first-year review, it began a Mid-Course Correction review in 1988 to examine area-of-review requirements, along with four other UIC program safeguards. As part of this effort, a panel of headquarters and regional staff, as well as state UIC program officials, plans to determine how effective the area-of-review requirement has been in identifying improperly plugged abandoned wells and whether the requirements should apply to all wells rather than only new wells. As of October 1988, EPA had begun to survey the states as to how they have been implementing area-of-review requirements. EPA staff expect to complete their work and develop recommendations for the Director of EPA's Office of Drinking Water in 1989.

State Efforts to Plug Improperly Plugged Abandoned Wells

According to EPA, there are approximately 1.2 million abandoned oil and gas wells, including formerly producing wells, in the United States. Of these, about 193,000, or roughly 17 percent of the total, may not be properly plugged. However, because of differences in construction practices and well depth, among other factors, the degree of risk from contamination from improperly plugged wells differs.

According to officials in Texas, Oklahoma, and Kansas, the number of improperly plugged wells may be growing. While New Mexico officials believe that they do not have a problem with abandoned wells, officials in the three other states told us that the number of improperly plugged wells in their states has been steadily rising in the last few years, as the decline in oil and gas activity has forced many operators into bankruptcy. Although these three states, as well as New Mexico, have plugging programs for abandoned wells, Texas and Oklahoma officials reported that they currently have more wells to be plugged than they can afford to pay for.

Texas, for example, has had a plugging program since 1965. Until 1983, the number of wells that were plugged with state funds ranged from 20 to 50 a year. By 1984, however, the total number of wells that were plugged rose to 177, and the state began to charge a $100 drilling permit fee that went into a plugging fund; the first year, $4.5 million was collected. However, because of the downturn in the oil industry, by 1987, drilling fee collections had dropped to $2 million, while the number of wells to be plugged went up to a total of 703. As of January 1988, the plugging fund contained $1.2 million, but the cost to plug the 489 wells

awaiting plugging was estimated to be $2.6 million, leaving a shortfall of $1.4 million. In addition, the state is now attempting to compel the owners of 6,350 abandoned and improperly plugged wells to properly plug them. Depending on the extent to which owners have the resources to pay for plugging, the state could have several thousand more wells to plug.

Oklahoma, which also has a plugging program, plugged 53 wells during fiscal year 1987 using about $122,000 in funds appropriated from general revenues, according to a state official. However, these were only purging wells—wells from which brine could be seen flowing at the surface. Although there were even more wells to be plugged the following year, fewer funds were available, according to the official, and only 19 wells were plugged—those that posed an immediate threat to water supplies and residents. In one field office in Oklahoma, the district manager told us that 149 unplugged abandoned wells had been reported to his office, but he did not have funds for plugging them. Noting that the number of unplugged abandoned wells has increased significantly in recent years, the district manager estimated that there were thousands of such wells in his district alone.

Kansas also maintains a plugging fund made up of permit fees and general revenues. A state law also allows abandoned wells to be plugged using proceeds from the sale of pipe and equipment left on-site. While these two means of paying for plugging have thus far been adequate, Kansas officials fear that with increases in the number of improperly abandoned wells being reported, their plugging programs may not be sufficient in the future. Although they did not know the precise number of unplugged abandoned wells, officials are aware that they have increased enormously in the last few years. In 1983, Kansas had to plug one well at a cost of $1,400, but by 1987, the state had 56 wells to plug, which cost $213,000.

Conclusions

Given the difficulties in detecting contamination and obtaining reports on contamination from affected individuals, the full extent to which Class II wells have contaminated drinking water is unknown. Nevertheless, for those cases that we know of, two points are striking. One is that UIC program safeguards have in some instances detected and prevented further contamination. Of the 27 known and suspected cases, close to half were discovered during routine pressure tests and record reviews. As a result, injection was halted until the wells could be reworked to correct the problem, or the wells were plugged.

The other point that stands out is that although the UIC program protects against continued contamination from structural deficiencies and improper injection, it does not always protect against contamination from a leading source: improperly plugged abandoned wells. Close to half of the known and suspected cases of contamination were the result of fluids flowing up through improperly plugged wells and entering USDWs. In these cases, contamination was allowed to spread until it had become extensive enough to incur noticeable damage, by making water undrinkable or ruining crops. EPA and the states have recognized that these types of wells are potential threats, and the four states in our review have programs to plug improperly plugged abandoned wells. However, these programs are not always adequate to plug all the wells that three of these states believe need or will need to be plugged.

While not all improperly plugged abandoned wells are immediate threats to drinking water supplies, those that are near operating injection wells can serve as conduits. For this reason, EPA and the states adopted the area-of-review concept, but they adopted it only for new wells, reasoning that all improperly plugged abandoned wells would eventually be discovered, although at a slower rate than if existing wells were also subject to the requirements.

Events occurring since EPA adopted the area-of-review concept have demonstrated—as EPA has recognized in its Mid-Course Correction review—that it is time to reconsider the decision to exempt existing wells from area-of-review requirements. Since 1980, several cases of contamination have been detected as a result of migration of fluids from existing injection wells into surrounding unplugged wells. While no one can say whether contamination would have been entirely prevented if area-of-review requirements had been imposed, the spread of injected fluids would more likely have been discovered and halted sooner.

Also, in the past 2 years, states have faced increasing demands on their plugging funds as oil and gas activity has declined and the number of improperly plugged abandoned wells has grown. By relieving well operators of the responsibility to identify and plug any improperly plugged abandoned wells in the vicinity of their injection operations, EPA has, in effect, transferred the costs to the states or, in those cases where states do not have sufficient funds, to the public whose drinking water supplies are in danger of becoming contaminated.

The importance of having sufficient safeguards is underscored by the fact that there are usually no practical remedies once contamination

occurs. For most of the 23 confirmed cases, the drinking water sources that were contaminated will remain so for years until natural processes restore water quality.

Extending the area-of-review requirement to existing as well as new Class II wells would affect a large number of wells—at least 70 percent of the estimated 88,000 wells in our universe—and thus could require states to devote additional resources to reviewing the information submitted by operators and ensuring that abandoned wells are properly plugged. However, to the extent that these existing wells are in the same area-of-review as new wells already permitted, the reviews for existing wells should have already been completed. In addition, because the degree of risk from contamination differs among existing wells, depending on well depth and construction practices, for example, not all area reviews conducted by operators would have to be reviewed at once by the state or EPA regulatory agency, but rather they could be reviewed over a period of time.

Recommendations

In order to better safeguard drinking water supplies from contamination from Class II wells, we recommend that the Administrator, EPA, require that UIC program regulations and/or guidance be established for state- and EPA-administered programs to make existing wells subject to area-of-review requirements as are new wells. Because of the large number of such reviews that would have to be conducted, EPA should establish a priority system to ensure that the regulatory agencies review those area reviews containing improperly plugged wells that pose the greatest environmental risks first.

Existing Safeguards Against Contamination Have Not Been Fully Implemented

On the basis of our review in late 1987 and early 1988, states' performance in implementing existing UIC program safeguards was mixed. Although the four state programs we examined are meeting most requirements for issuing permits, a considerable portion of their well files did not contain sufficient documentation to support issuance of injection well permits. In addition, Kansas, Oklahoma, and Texas have not finished reviewing the files of rule-authorized, or existing wells, with Oklahoma and Texas taking longer than the 5-year period that EPA's guidance allowed. Similarly, Oklahoma and Kansas have not finished pressure testing about 44 percent of their existing wells. Kansas and Oklahoma are also not monitoring the activities of many of their wells. Finally, while all four states require proper plugging and abandonment procedures, only two provide for financial responsibility on the part of the operator. The others rely instead on state plugging funds, which, as noted in chapter 2, have not always been sufficient to pay for all the wells that have to be plugged.

EPA regions are aware of delays in program implementation and problems with financial surety, and EPA has increased state program funding and created a financial surety task force to address these problems. However, although EPA has been assessing the states' programs, the agency has not been aware of the extent of gaps in documentation.

Class II Program Safeguards

As noted in chapter 1, the Safe Drinking Water Act gave states considerable discretion in their programs to regulate Class II wells, requiring only that they demonstrate that they were protecting drinking water sources and included inspection, monitoring, recordkeeping, and reporting practices. EPA guidance specified a number of basic safeguards to be included in state programs, including

- area-of-review, mechanical integrity tests, and construction requirements for wells that have permits;
- file reviews and mechanical integrity tests for rule-authorized wells; and
- inspections and operator reports (as monitoring devices) and proper plugging and abandonment procedures, including some form of financial responsibility for plugging both types of wells.

We found that all four states—Kansas, Oklahoma, New Mexico, and Texas—had adopted these safeguards in some form. As discussed in the following sections, however, the procedures followed and the extent to which they have been implemented differ.

Requirements for Permits Are Not Fully Documented

In order to obtain a permit to operate a Class II well, states require operators to, among other things (1) meet certain construction standards including those for surface casing, (2) search for and plug any abandoned unplugged wells in the area-of-review (as discussed in chapter 2), and (3) conduct a mechanical integrity test. While surface casing requirements vary among and even within states, state programs generally require that new wells be constructed with surface casing that protects the lowest USDW. Files on the new wells we examined showed that this standard was met.[1] However, we found that many wells with permits contain no evidence in their files that area-of-review information was checked or that the pressure test portion of mechanical integrity tests was conducted.

To make sure that government programs are operating efficiently and accomplishing their objectives, program managers should have in place a system of internal controls. According to standards for internal controls developed by GAO in 1983,[2] significant agency transactions and events are supposed to be properly recorded.

We found, however, that the four states did not have internal controls in place to ensure that all necessary documentation was on file. For example, for all types of wells with permits we found that, in general, files had information on the status of wells, both active and abandoned, within the area-of-review: in Kansas, 100 (65 to 100) percent; in Oklahoma, 88 (68 to 97) percent; and in Texas, 100 (89 to 100) percent of the files met this requirement. (In New Mexico, 100 (37 to 100) percent of the files also had met this requirement, but this estimate is based on a very small number of wells; hence, the broad confidence interval.) In none of the states, however, did UIC program staff document their reviews of the information submitted to meet area-of-review requirements.[3] Although staff in New Mexico, Kansas, and Oklahoma told us

[1]Because all 14 of the new wells in our sample met this standard, we cannot compute a meaningful estimate for our universe. At the individual state level, the estimates are Oklahoma, 100 (47 to 100) percent; Texas, 100 (55 to 100) percent; Kansas, 100 (47 to 100) percent; and New Mexico, 100 (4 to 100) percent. These calculations are based on very small numbers of wells; hence, the broad confidence intervals.

[2]Internal controls that federal agencies are required to follow are set forth in GAO's Standards For Internal Controls in the Federal Government, published in 1983 pursuant to the Federal Managers Financial Integrity Act of 1982.

[3]Because none of the 59 permitted wells in our sample showed any evidence of such a check, we cannot compute a meaningful estimate for our universe. At the individual state level, the estimated percentages of wells without documentation are Oklahoma, 100 (88 to 100) percent; Texas, 100 (89 to 100) percent; Kansas, 100 (65 to 100) percent; and New Mexico 100 (37 to 100) percent. These calculations are based on small numbers of wells and therefore have broad confidence intervals.

that they checked the information that permit applicants submitted against state maps and plugging records, we found no evidence of such a check. Moreover, while examining the files, we could find no evidence that state program staff had ever found improperly plugged wells. In Texas, officials acknowledged that they rarely reviewed the accuracy of information submitted to satisfy area-of-review requirements because of the time and staff required. The state now has a pilot project underway, funded by EPA, to determine the costs of checking area-of-review information.

Documentation was also missing from program files on mechanical integrity tests (MITS). MITS are performed in two parts: the first part is a check of cementing and other records in order to verify that enough cement was used to ensure that fluids are not migrating from the injection zone; the second part is a check for leaks in the well casing and tubing, either by annulus pressure tests, monitoring, or other means. For new wells, MITS are supposed to be conducted before injection can begin and every 5 years thereafter.

Overall, 41($\pm$14) percent of the files in our universe had no documentation indicating that pressure tests had been conducted before the wells were allowed to begin operating. In Texas, the UIC program director explained that before 1986, the state did not require operators to submit this information. We found that those wells in Texas that had no record of pressure tests had all been issued permits before 1986 and were therefore not required to submit evidence. In Oklahoma and Kansas, program officials believed that the necessary tests had been conducted but that the reports documenting them had not been correctly filed or received from the states' district offices. EPA regional officials told us they had known of problems with missing documentation but were not aware they were as extensive as our review found. In New Mexico, the files in our universe had documentation indicating that pressure tests had been conducted before the wells were allowed to begin operating.

Existing Wells Have Not Been Fully Reviewed and Tested

According to EPA guidance, states were to review the files and test the mechanical integrity of all existing, or rule-authorized, wells within 5 years of achieving primacy to make sure that the wells are not endangering USDWS. As of the end of 1987 and early 1988, these reviews and tests were not complete, however.

File Reviews

File reviews are supposed to verify the following:

1. Each well extends below the lowermost USDW and has an adequate confining zone separating the injection zone from that USDW.

2. Each well is designed for the expected use and local geological conditions.

3. Each well is cased and cemented to prevent movement of fluids in or between USDWs.

4. Each well is operated at an appropriate pressure and with adequate controls to prevent fracturing of the confining zone.

5. Each well operator is monitoring and reporting as required.

6. Each well owner/operator is maintaining appropriate financial surety and plugging and abandonment plans.

In order to check on the first three items, state officials rely on operators' well completion reports, which contain information on the depth of the well, the length of the casing, and the extent of cementing. To check on well pressures, officials examine the operator's permit and the pressure authorized at issuance. Those states that require financial surety on the part of the well operator check the currency of financial information, and to monitor well activities, officials check to see whether operator reports, describing the current status of the well and monthly pressure readings, are on file.

Three of the four states in our review achieved primacy more than 5 years ago: New Mexico and Texas in 1982, and Oklahoma at the end of 1981. Since Kansas obtained program primacy in February 1984, its 5-year period just concluded. However, overall, at the time of our review only 32(±18) percent of the necessary file reviews had been completed. New Mexico conducted an equivalent review before it received primacy and was therefore given credit for having met this requirement by EPA. Oklahoma had completed 36(±16) percent of its file reviews and Texas, 29(±10) percent. Kansas had completed reviews on 7(±7) percent of its files.[4]

[4]Although Kansas officials claimed that 23, or 41 percent of our sample files, had been reviewed, 19 of these files were reviewed at the field level and state files did not contain documentation on these reviews. We were therefore able to verify only those 4 files reviewed by the state, which comprised 7 percent of our sample files.

In these three states, file reviews have been hampered by the large number of wells to review, incomplete information in the files, and insufficient staff and resources. With over 43,000 existing wells, Texas was skeptical from the start that it could complete its file reviews within 5 years, and its original memorandum of agreement with EPA, under which the state was delegated primacy, contained no deadline for completing its file reviews. The state did relatively few file reviews until January 1987, when it received a 3-year, $750,000 grant from EPA, which it has used to hire 12 staff members. Texas officials said that as of December 1987, they had completed file reviews of 9,768 wells, finding numerous instances of missing well completion reports, along with wells that were being regulated but had never been authorized to inject by the state. In these cases, operators are required to apply for a permit according to procedures. The state expects to complete all its file reviews by January 1990.

With almost 13,000 Class II wells to review, Oklahoma also faced a major undertaking, which similarly was slow to start. According to the state's UIC program director, although Oklahoma achieved primacy in 1981, it did not begin its review of rule-authorized wells until 1985 because until that time Oklahoma focused on permitting. At that point, after EPA expressed its concern about the state's lack of progress, the state hired a program director and instituted file reviews and other procedures. However, once file reviews began, reviewers found that much of the information they needed—mostly well completion reports—was missing and had to be obtained from well operators. In 1986, EPA region VI granted Oklahoma another 2 years to complete its file reviews, until December 1988, and also gave the state additional funding for its program. Since then, EPA has granted Oklahoma an additional extension to September 30, 1989.

Kansas' file reviews were also slowed by missing well completion information and a late program start. When Kansas was granted primacy, its program was jointly administered by two state agencies that disagreed over how the program should be run. Implementation was consequently delayed until 1986, when a single state agency assumed responsibility for the program. Once the file reviews got underway, program officials discovered that many files lacked well completion reports. As a result, the state began to require operators of existing wells to submit well completion information along with the results of pressure tests. Kansas officials expect to complete their file reviews sometime in 1989.

Mechanical Integrity Tests

Along with file reviews, MITs are the principal means by which authorities can ensure that existing Class II wells are not contaminating drinking water. According to EPA guidance, operators were to conduct the pressure test portion of the MITs within the same 5-year period as the file reviews. At the time of our review, however, 69($\pm$16) percent of the required pressure tests overall had been conducted within the last 5 years.

In Texas, 93($\pm$6) percent of the wells either had pressure tests completed or had been equipped with continuous monitoring devices. In New Mexico, 81($\pm$18) percent of the wells had annulus pressure tests.

However, in Oklahoma, only 44($\pm$16) percent of the wells and in Kansas, only 44($\pm$13) percent of the wells had been tested within the last 5 years, in both cases, because incomplete and incorrect inventories of wells delayed the states' scheduling of pressure tests. As discussed further in the next section, it is the policy of both states to have inspectors witness as many pressure tests as possible. According to program officials, inspectors were often unable to locate wells that were listed in their inventories. In other instances, inspectors were sent out to a well only to discover that the test had already been conducted.

As with the MITs for wells with permits, Kansas program officials believed that tests had been conducted on many more existing wells and were surprised to learn that our sample results were much lower. Oklahoma officials and EPA officials in region VI recognized that progress had been slow, but they are hopeful that with the addition of funds and staff, the tests will be completed by September 30, 1989.

Operators Are Not Consistently Monitored

To help ensure that operators are meeting the terms of their permits, UIC programs contain provisions for inspection and monitoring. According to EPA guidance, state programs are supposed to provide for qualified state inspectors to witness at least 25 percent of the MITs conducted each year. To monitor activities on an ongoing basis, program officials rely on operator reports, submitted at least once a year and containing information on the injection pressures and volume of fluids injected each month.

We found that each of the four states has inspectors to witness MITs. Kansas, New Mexico, and Oklahoma require inspectors to witness as many MITs as possible, and we estimate that 72 percent or more of the MITs conducted in each of these three states had been witnessed. Texas'

policy is for inspectors to witness at least 25 percent of the MITS, and we found that state inspectors had witnessed 29(±12) percent of the MITS.

Monitoring of operator activities was less consistent. While New Mexico had operators' annual reports on file for all or most of its wells (100 [88 to 100] percent) and Texas for nearly all its wells (96[±4] percent), Kansas had only 48(±13) percent of the required reports, and Oklahoma had only 25(±11) percent. Both Kansas and Oklahoma attribute this situation to incomplete inventories of Class II wells. Unlike New Mexico and Texas, which have computerized inventories, Kansas and Oklahoma are still in the process of compiling their inventories, with district offices gathering information as inspectors witness MITS. Once the inventories are complete, Kansas and Oklahoma officials said they will be able to check their files to ascertain whether they contain current operator reports and to send out notices when reports are found to be missing, as is done in Texas and New Mexico.

Kansas officials expect to have their inventory completed in 1989, while Oklahoma program officials expect their inventory will be completed once all the MITS have been conducted, in 1989.

Financial Surety Requirements Are Not Working

EPA guidance for state programs calls for Class II wells to be properly plugged upon abandonment, in a manner that will not allow the movement of fluids into or between USDWS. The guidance also calls for operators to maintain financial responsibility for plugging their wells but does not specify the forms it must take.

While all four states in our review have adopted requirements for plugging and abandonment, only New Mexico and Oklahoma require operators to provide some form of financial assurance, while Kansas and Texas use their state-administered plugging funds in lieu of requiring operators to maintain financial responsibility. New Mexico requires operators to provide a performance bond, either for a single well or an entire field, and we found that all or most wells (100 [88 to 100] percent) had evidence of surety on file that was current.

Oklahoma requires either a bond, a letter of credit, or a financial statement showing a net worth of at least $50,000. However, state officials have encountered problems with financial statements, claiming that many operators who were allowed to furnish financial statements went bankrupt and left no assets for plugging. According to our data, 41(±12) percent of the wells in Oklahoma with evidence of financial

surety on file are covered by this form of assurance. In 1986, the state legislature tightened the requirements for financial statements by requiring operators of new wells to have bonds for at least 3 years before they can use financial statements as financial surety.

Even with this change, however, the state may still encounter problems. Twenty-four($\pm$ 18) percent of the wells in Oklahoma with financial statements on file as evidence of financial ability showed a net worth of less than $50,000. We also found that 18($\pm$ 10) percent of all forms of financial surety on file in Oklahoma, including financial statements, had expired or were not current.

Although EPA allowed Texas and Kansas to use their plugging funds instead of requiring operator financial responsibility, as discussed in chapter 2, Texas' fund is inadequate to pay for plugging all the known abandoned wells and Kansas' fund may not be sufficient in the future to plug increasing numbers of abandoned wells. The director of Texas' UIC program told us that the state has been looking into the possibility of requiring operator financial surety, although there is some concern about operators' ability to pay for bonds or other forms of surety. While Kansas has no plans to require operator surety, the UIC program official in charge of compliance is concerned that if the number of abandoned wells that are improperly plugged continues to grow at current rates, the plugging fund may become inadequate.

According to an EPA official, along with its Mid-Course Correction review, EPA is looking at the need for changes in financial surety requirements. While continuing to examine long-range issues, such as the viability of financial statements, an EPA work group has developed recommendations for immediate implementation that included requirements for annual updates of financial statements as well as updates of plugging and abandonment costs.

EPA Oversight of State Programs

In addition to the Mid-Course Correction review of the Class II program, which is looking at program requirements, EPA regulations also call for the agency to evaluate how well states are implementing their programs. According to EPA regulations, states are supposed to report to EPA annually on the implementation of their programs and quarterly on cases of noncompliance with permit requirements. On the basis of the states' reports and visits to the states, the EPA regions prepare annual assessments of each state's progress in implementing its program.

While we found that regional officials were reasonably familiar with the status of the four state programs we examined, their knowledge of the programs was based on general observations rather than on an in-depth review of well records, such as ours. EPA's annual evaluations have focused on more fundamental program implementation issues, such as staffing, funding, and adoption of regulations. As noted earlier, EPA officials in regions VI and VII, which have oversight over the four states in our review, believe that while Texas, Kansas, and Oklahoma were slow to put their programs into place (particularly the latter two states), the states have made progress in the last few years.

However, EPA is concerned about the adequacy of the states' data management systems and the accuracy of their reporting. Our findings reinforce the agency's concerns. In particular, we found that the information reported to EPA by Kansas and Oklahoma on completed file reviews and MITs differs from what we found in well records. For example, as shown in table 3.1, Oklahoma reported to EPA that by the end of 1987, about the same time we looked at well records in the state, it had completed 66 percent of its file reviews. Our review of records, however, found that a smaller portion of the file reviews had been completed—36($\pm$ 16) percent. Similarly, Oklahoma reported a higher completion rate for pressure tests than our record checks revealed. In Kansas, the difference between what we found and what the state reported is quite wide, the result, according to state officials of having some records kept in field offices, while others are kept in the central state office, where our review was conducted.

Table 3.1: Comparison of Selected State-Reported and GAO Data for Existing Wells (Percent)

	File reviews completed[a]		Pressure tests (MITs) completed[a]	
	State data[b]	GAO data	State data[b]	GAO data
Kansas	72	7(±7)[c]	60	44(±13)
New Mexico	[d]	[d]	[e]	81(±18)
Oklahoma	66	36(±16)	73	44(±16)
Texas	38	29(±10)	84	93(±6)

[a]Our estimates are for active and temporarily inactive wells in EPA's FURs inventory as of October 1987. EPA's data relate to similar wells listed in FURs as of December 1987.

[b]EPA officials said they consider these numbers to be estimates because the number of existing wells in the states' inventories is difficult to determine.

[c]State officials believe the actual percentage of completed file reviews within our sample was 41 percent. (See footnote 4 on p. 36.)

[d]New Mexico conducted an equivalent review before receiving primacy and was therefore considered to have already met this requirement.

[e]Since New Mexico requires a pressure test annually, the number of tests it reported is greater than the number of existing wells.

To address its concerns, EPA has begun a complete review of UIC program data needs and management systems. After identifying EPA headquarters' information needs, the agency plans this year to identify a minimum set of data elements to be collected and kept by the states and regions on a well-by-well basis. EPA expects that it will take about 5 years to have a satisfactory system in place for every program.

Conclusions

Under the wide latitude allowed by federal law, states have adopted those safeguards that EPA has determined to be fundamental to protecting USDWs from contamination. Most of the states we visited, however, have taken a long time to review existing wells and after 4 to 5 years, many of these wells had still not been reviewed and tested. The states and EPA are aware of this situation, however, and believe that the problems that caused these delays—lack of sufficient staff and resources to deal with the large number of wells—are being addressed. According to state officials, remaining file reviews and pressure tests should be completed within the next year or two.

EPA also realizes that financial surety requirements have to be strengthened. Although intended to ensure that operators would not abandon their wells without properly plugging them, financial surety has not always been effective in guaranteeing that funds will be available for plugging. In view of the large number of improperly plugged abandoned

wells in the United States and the potential for contamination they represent, preventing any increase in their numbers should be a high priority. EPA's task force is an important effort toward this end.

On the basis of our findings, we also support EPA's efforts to improve its internal controls over the UIC program by developing better data management systems. Specifying precisely what information should be kept in the records of each well is an important step in helping ensure that the data that are reported by the states are accurate and reliable.

By contrast, EPA was not aware of the extent of problems with new permits. Although operators are supposed to pass a pressure test and search for and plug any improperly abandoned wells in their area-of-review before they can receive their permits, states issued a considerable number of permits, without any evidence on file that these requirements had been met or checked. EPA needs to make sure that states are issuing permits only if sufficient evidence exists that pressure testing is performed and area-of-review information is checked.

Recommendation

To help ensure that Class II wells are structurally sound and not injecting into areas of unplugged wells, we recommend that the Administrator, EPA, require state program regulatory agencies to institute the internal controls necessary to ensure that Class II permits are issued only if documentation exists that area-of-review information was checked and the pressure test portion of mechanical integrity tests was conducted.

Methodology

Our review focused on active and temporarily inactive (we are using the term temporarily inactive to refer to EPA's category of temporarily abandoned wells) Class II wells in the 20 states that had primary regulatory authority at the time of our analysis. As table I.1 shows these states contain a total of 134,729 active and temporarily inactive wells, which represent about 87 percent of all such wells in the United States.

Table I.1: Active and Temporarily Inactive Class II Wells in Primacy States (As of October 1987)

State	Number of wells
Texas	49,476
Oklahoma	22,579
Illinois	14,147
Kansas	14,009
California	11,201
Wyoming	5,749
Louisiana	4,212
Ohio	3,952
New Mexico	3,913
Arkansas	1,128
Colorado	932
West Virginia	760
Utah	664
Nebraska	624
North Dakota	595
Missouri	275
Alaska	266
Alabama	206
South Dakota	40
Oregon	1
Total	**134,729**

Source: EPA, FURS.

In choosing our sample from among these states, we excluded Illinois because EPA had conducted an extensive study of Illinois' program in 1986. This exclusion left 120,582 active and temporarily inactive Class II wells in our universe of interest.

Our sampling then proceeded in two stages. In the first stage, we randomly selected four distinct states, with the probability of their selection proportional to the total number of active and temporarily inactive

Class II wells in each state.[1] The information on Class II active and temporarily inactive wells in the four states came from EPA's FURS. Each time a state was selected meant that in the second stage of sampling, we would take a sample of 25 wells from that state. Thus, since Texas was selected five times, the total number of Texas wells that would be included in the sample was 125. In the second stage of sampling, we randomly selected a total of 350 wells from these four states. (See table I.2.)

Table I.2: Sample of State-Regulated Active and Temporarily Inactive Class II Wells

State	Number of times selected	Number of wells	Proporation of wells of interest	Number of wells sampled	Number of wells reviewed
Texas	5	49,476	.410310	125	108
Oklahoma	4	22,579	.187250	100	63
Kansas	4	14,009	.116178	100	61
New Mexico	1	3,913	.032451	25	24
Total		**89,977**	**.746189**	**350**	**256**

Of our 350 sample wells, we filled out data collection instruments (DCIs) for 256 wells, or 73.1 percent of the wells sampled. We did not fill out DCIs for the remaining 94 wells because of discrepancies between EPA and state records. The specific reasons for not filling out DCIs are listed in table I.3.

Table I.3: Reasons for Not Filling Out DCIs on Sample Wells

	Number of wells				
Reason	**Texas**	**Oklahoma**	**Kansas**	**New Mexico**	**Total**
FURS inventory contained more wells for a single permit than state files	•	29	17	•	46
Not an active or temporarily inactive well[a]	11	6	14	1	32
Permit application withdrawn	6	•	3	•	9
No file found for well in state records	•	2	5	•	7
Total	**17**	**37**	**39**	**1**	**94**

[a]Files showed that the wells had been plugged, converted to a production well, had never been activated, or were not injection wells.

Because we reviewed a statistical sample of wells, each estimate developed from the sample has a measurable precision, or sampling error.

[1]We randomly selected the four distinct states with replacement. This means that each time we selected a state from our 19-state universe of interest, its selection was noted and then it was returned to the universe prior to the next selection. Thus, a particular state could be selected more than once before we selected our four distinct states.

The sampling error is the maximum amount by which the estimate obtained from a statistical sample can be expected to differ from the true universe characteristic (value) we are estimating. Sampling errors are stated at a certain confidence level—in this case, 95 percent. This means that the chances are 19 out of 20 that, if we reviewed all of the Class II wells in our universe, the results of such a review would differ from the estimate obtained from our sample by less than the sampling errors of such estimates.

Our sample estimates represent approximately 88,000 (± 10,400) active and temporarily inactive Class II wells in the universe of interest—19 primacy states. These estimates represent Class II active and temporarily inactive wells that we would expect (1) to have been listed in the FURS inventory as of October 1987 and (2) to have files at the state level that would enable us to fill out a DCI on each well.

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Why Oilwells Leak: Cement Behavior and Long-Term Consequences

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Abstract

Oil and gas wells can develop gas leaks along the casing years after production has ceased and the well has been plugged and abandoned (P&A). Explanatory mechanisms include channelling, poor cake removal, shrinkage, and high cement permeability. The reason is probably cement shrinkage that leads to circumferential fractures that are propagated upward by the slow accumulation of gas under pressure behind the casing. Assuming this hypothesis is robust, it must lead to better practice and better cement formulations

Introduction, Environmental Issues

This discussion is necessarily superficial, given the complexity of the issue and attendant practical factors such as workability, density, set retardation, mud cake removal, entrainment of formation gas, shale sloughing, pumping rate, mix consistency, and so on. A conceptual model will be developed in this article to explain slow gas migration behind casing, but we deliberately leave aside for now the complex operational issues associated with cement placement and behavior.

In 1997, there were ~35,000 inactive wells in Alberta alone, tens of thousands of abandoned and orphan wells[1], plus tens of thousands of active wells. Wells are cased for environmental security and zonal isolation. In the Canadian heavy oil belt, it is common to use a single production casing string to surface (Figure 1); for deeper wells, additional casing strings may be necessary, and surface casing to isolate shallow unconsolidated sediments is required. As we will see, surface casings have little effect on gas migration, though they undoubtedly give more security against blowouts and protect shallow sediments from mud filtrate and pressurization.

To form hydraulic seals for conservation and to isolate deep strata from the surface to protect the atmosphere and shallow groundwater sources, casings are cemented using water-cement slurries. These are pumped down the casing, displacing drilling fluids from the casing-rock annulus, leaving a sheath of cement to set and harden (Figure 1). Casing and rock are prepared by careful conditioning using centralizers, mudcake scrapers, and so on. During placement, casing is rotated and moved to increase the sealing effectiveness of the cement grout. Recent techniques to enhance casing-rock-cement sealing may include vibrating the casing, partial cementation and annular filling using a small diameter tube.

Additives may be incorporated to alter properties, but Portland Class G (API rating) oil well cement forms the base of almost all oil well cements.[2] Generally, slurries are placed at densities about 2.0 Mg/m^3, but at such low densities will shrink and will be influenced by the elevated pressures (10-70 MPa) and temperatures (35 to >140ºC) encountered at depth.

The consequences of cement shrinkage are non-trivial: in North America, there are literally tens of thousands of abandoned, inactive, or active oil and gas wells, including gas storage wells, that currently leak gas to surface. Much of this enters the atmosphere directly, contributing slightly to greenhouse effects. Some of the gas enters shallow aquifers, where traces of sulfurous compounds can render the water non-potable, or where the methane itself can generate unpleasant effects such as gas locking of household wells, or gas entering household systems to come out when taps are turned on.

Methane from leaking wells is widely known in aquifers in Peace River and Lloydminster areas (Alberta), where there are anecdotes of the gas in kitchen tap water being ignited. Because of the nature of the mechanism, the problem is unlikely to attenuate, and the concentration of the gases in the shallow aquifers will increase with time.

This implies that current standards for oilwell cementing and P&A are either not well founded, or the criteria are based on a flawed view of the mechanism. This is not a condemnation of industry: all companies seek to comply with standards.[3] Nevertheless, we believe that the AEUB Interim Directive 99-03[4] is flawed with respect to gas leakage around casings. To rectify this, the mechanisms must be identified correctly. Practise can then be based on correct physical mechanisms, giving a better chance of success (though we do not believe

that the problem can be totally eliminated because of the vagaries of nature and human factors, despite our best efforts).

There is also need for better quality oil-well cement formulations that can resist thermal shocking. For example, leakage of fluids along thermal wells in cyclic steam operations in Alberta has proven a challenging problem for Imperial Oil.[5] If poor quality or poorly constituted cement is used, high injection pressures, thermal shocking, plus non-condensible gas evolution lead to leakage behind the casing that could break to surface under exceptional conditions.

Finally, in production management for conservation purposes, zonal isolation is multiple-zone wells.[6]

There are initiatives to identify old leaking wells and undertake mitigating action in Alberta and Saskatchewan, the "orphan well" program of the AEUB, initiatives by the Petroleum Technology Alliance Centre in Calgary, and so on. This article is to try and clarify the mechanisms involved.

Cement Behavior

Cement Shrinkage: If cement is placed at too high a water content, it loses water to the porous strata under lower pressure (p_o) through direct filtration because the cement hydrostatic head is greater than the pore water pressure head. The annulus width between casing and rock is small (e.g. 175 mm casing in a 225 mm hole = 25 mm), so even a small shear strength development between rock and cement will support the weight of the cement. If this shear stress is only ~0.5 kPa, the entire "hydrostatic" head of the cement ($\gamma_c \cdot z$) can be supported by stress transfer to the rock mass. (Of course, because of temperature and pressure effects, this degree of set is not attained simultaneously along the entire cement sheath.)

Thus, while the cement is still in an almost liquid, early-set state, massive shrinkage can occur by water expulsion, but annular cement settling to compensate for the loss of water is impeded by the shear stress transfer to the rock mass. The consequence is shrinkage in the cement sheath.

Portland cements continue to shrink after setting and during hardening.[7,8] This autogenous shrinkage occurs because hydration reaction products occupy less volume than the original paste. Judicious proportioning control of the cement slurry and the use of admixtures and additives can limit the physico-chemical effects of the autogenous shrinkage processes. Mostly, the careful control of water content by using superplasticisers and the control of macro-shrinkage by using appropriate aggregates benefit the properties of the set grouts.

Silica flour (SiO_2, ground to –20 μm) is often used to make "thermal cement". It is added in quantities approaching 75% of the dry constituents, the remainder being cement powder. Silica flour has also been added to cement in an attempt to counteract shrinkage. Unfortunately, for physico-chemical reasons, silica flour can enhance both drying and autogenous shrinkage.[9]

Silica flour is a ground product, usually made from pure quartz sand. Physically, the silica flour, by virtue of its grain size ($D_{50} \approx$ 10-20 μm) has a large surface area; this provides not only enhanced reaction areas for kinetically controlled hydration processes, it provides a need for additional wetting for slurry formulation. Physico-chemically, a freshly fractured silica surface possesses a high chemical reactivity because of the presence of unsatisfied bonds arising from the breaking of the silica chemical lattice. These fresh surfaces will electrostatically bind polar water molecules to satisfy these broken bonds. Experiments on pure silica using magnetic resonance and dielectric permittivity show that up to 9-11 layers of water can be absorbed on the surface, and the closest layers are of course the most tightly bound.

The surface area increases inversely as the square of the mean particle diameter, therefore reducing the surface area by a factor of five (grinding 100 μm sand to 20 μm flour) increases the area by 25, and because the new surface area is chemically fresh, it is more reactive. Thus, the electrostatic bound water volume for silica flour is vastly larger than for geochemically "old" sand. Furthermore, electrostatically bound water thickness is reduced by temperature (Brownian motion), so cool slurry will have a surfeit of water when it becomes heated through contact with geothermal temperature.

Alternative fillers are required to control the macro-shrinkage properties of the materials. We recommend 60-100 μm quartz sand be substituted for SiO_2 flour when possible.

Other processes can lead to cement shrinkage. High salt content formation brines and salt beds lead to osmotic dewatering of typical cement slurries during setting and hardening, resulting in substantial shrinkage.[10,11] Experiments with recommended cement grout formulations placed against salt and potash strata clearly show massive dewatering of the cement and the formation of free brine at the interface between the cement and the salt. The same effect must occur when fresh-water cement grouts are in contact with low permeability rocks with highly saline pore fluids. By ensuring that the grouts are placed at high density, conducive to a stable grout microstructure, the effects of osmotic dewatering can likely be minimized, but this should be quantitatively assessed.

Recently marketed finely ground cements (Microfine™ and Ultrafine™) are Portland cement-based materials. They are generally finer than normal Portland cements and include pozzolanic additives, such as finely ground pumice. Slurries of these materials penetrate fine fissures and pores in rock more readily than more conventional grouts but in bulk suffer from very high shrinkage and, hence, without further modification, are not suitable for grouting the annulus between oil-well casings and the borehole wall.[12]

Dissolved gas, high curing temperatures, and early (flash) set may also lead to shrinkage. It is not clear if non-shrinkage additives have substantial positive effects at great depth and high temperature. These additives (e.g. Al powder) generally produce some gas, which in the laboratory provides volume increase. Additives may enhance some properties; however, they may induce negative impacts on other properties, or lose effectiveness at elevated temperatures, pressures, or in the presence of certain geochemical species. Also, autogeneous shrinkage continues long after these agents have acted.

Cement Strength and Rigidity. API standards for oilwell cement specify certain strength criteria. Strength is not the major issue in oil well cementing under any circumstances. Based on extensive modelling, cement clearly cannot resist the shear that is the most common reason for oilwell distortion and rupture during active production.[13] If compaction or heave (from solids injection) is taking place, the cement itself provides minimal resistance to buckling (compression) or thread popping (tension). If the annulus could be filled with relatively dense sand, the resistance to shear would be better than current ordinary oilwell cement formulations.

Based on over 50 triaxial tests at various confining stresses, we have shown that 28-day cured oilwell cements are contractile (volume reduction during shear) at all confining stresses above 1 MPa (150 psi). This is also the case for 70% silica flour cements, and for the new products based on extremely finely ground cement. (Specimens were cured under water at 20°C or at 90°C.) However, dense concretes used in Civil Engineering are dilatant, and therefore resistant to shear, at all working stresses.

The stiffness modulus of typical oilwell cement is small compared to that of low porosity rocks, and vastly lower than that of steel.[14] The stiffness moduli are roughly 2-4% that of steel, though there is a wide range depending on density, content, and confining stress. Depending on depth (~stress) and induration (~porosity), rock moduli may vary from 2% to 50% of steel, and a reasonable value is 5-15% in most intermediate cases of moderate porosity (10-20%).

Bond. Cement will not bond to salt, oil sand, high porosity shale, and perhaps other materials. Also, bond strength (i.e. the tensile resistance of the cement-rock interface) is quite small; in fact, the tensile strength of carefully mixed and cured oilwell cement at recommended formulations is generally less than 1-2 MPa. Given that fluid pressures of 10's of MPa may have to be encountered, given that pressure cycling of a well can easily debond the rock and cement (there is strain incompatibility because of the different stiffnesses), and given that de-bonding is generally a fracturing process with a sharp leading edge rather than a conventional tensile pull-apart process, a large cement bond to rock cannot be assumed in any reasonable case. Initiation and growth of a circumferential fracture ("micro-annulus") at the casing-rock interface will not be substantially impeded by a cohesive strength at this interface.

The presence of "good bond" on a cement bond log is in fact not an indicator of bond, but an indicator of intergranular contact maintained by a sufficient radial effective stress. The lack of bond on a bond log is actually evidence of the inability to transmit high frequency sonic impulses because of the presence of an "open zone", that is, a circumferential fracture that is open by at least a few microns. Thus, maintaining "bond" actually means maintaining effective radial stress. Note that if effective radial stress cannot be maintained, then hydraulic fracturing conditions must exist at the interface.

The Gas Leakage Model

A good conceptual model must explain the following typical aspects of oilwell behavior that are observed in practice.

- Generally there are no open circumferential fractures detectable after a typical good quality cement job ("good bond" is observed on the log traces).
- Such fractures develop over time and with service.
- Even in cases where bond appears reasonable over substantial sections of the casing, gas leakage may be evidenced some years or decades later.
- The process is invariably delayed; thus, there must be physically reasonable rate-limiting processes.
- The gas often appears at surface rather than being pressure injected into another porous stratum encountered in the stratigraphic column.
- The presence of surface casing provides no assurance against gas leakage.

Whereas we do not deny that mud channeling, poor mud cake removal, gas channeling, and so on can occur in isolated cases, we believe that a better hypothesis exists to rationally explain the points listed above.

Figure 2 shows the effect of shrinkage on near-wellbore stresses. (Plots are qualitative, but have been confirmed by numerical modeling, to be published later.) Initially, cement pressure $p_c(z) = \gamma_c \cdot z$, almost always higher than p_o, but lower than σ_{hmin} (lateral minimum total stress). Set occurs and a small amount of shear stress develops between the rock and the cement; then, hydrostatic pressure in the cement is no longer transmitted along the annulus. Thereafter, even minor shrinkage (~0.1-0.2%) will reduce the radial stress ($\sigma_r = \sigma'_r + p_o$) between cement and rock because rock is stiff (4-20 GPa for softer rocks), and small radial strains (0.001-0.003) cause relaxation of σ_r and increase in σ_θ. A condition of $p_o > \sigma_r$ (σ_3) is reached; i.e. the hydraulic fracture criterion. A circumferential fracture (i.e. $\perp$ to $\sigma_3 = \sigma_r$), typically no wider than 10-20 µm, develops at the rock-cement interface.

A thin fracture aperture is sufficient to appear as "loss of bond" in a geophysical bond log. Because in situ stresses are always deviatoric (e.g. $\sigma_{hmin} \neq \sigma_{HMAX}$), bond loss will usually appear first on one side of the trace, or on two opposite sides (direction of σ_{hmin}). Wells that have experienced several pressure or thermal cycles will almost always show loss of bond, sometimes for vertical distances in excess of 100 m.

A zone of $p_o > \sigma_r$ (σ_3) can extend for considerable heights. Nevertheless, this is still not a mechanism for vertical growth. To understand vertical growth, consider Figure 3, where a hypothetical case is presented. The static circumferential fracture of length L is filled with formation water of density γ_w, giving a gradient of about 10.5 kPa/m for typical oilfield brine, but the gradient of lateral stress ($\partial\sigma_h/\partial z$) is generally on the order of 18-24 kPa/m. This means that if the fracture contains a fluid pressure sufficient to just keep it open at the bottom, there is an excess pressure at the upper tip equal to ~$L \cdot (21-10.5) \approx$ about 10 kPa/m, in typical Alberta conditions, for example. Thus, because of the imbalance between the pressure gradient in the fracture and the stress gradient in the

rock, an inherent fracture propagation force is generated that tends to drive the circumferential fracture upward. (In a perfectly horizontal section, this cannot happen, but the process develops equally at higher elevations in the well where it becomes inclined.)

Now, consider what happens when a circumferential fracture between the cement and the rock is exposed to a thin stratum that contains free gas (there are invariably several such zones in any well). Cementing a casing leads not only to the development of a cement sheath, but the cement paste also slightly penetrates the interstitial space in the surrounding rock (a few grain diameters deep for typical sandstone). This reduces the permeability substantially, and because of capillary exclusion effects associated with two-phase flow and the reduced pore throat diameter arising from cement particle invasion, gas flow into the circumferential fractures is almost certainly through diffusion. This means that when the fracture is small, the rate of gas influx is modest. However, as the fracture grows in height, the contact area with surrounding sediments increases, and eventually (and particularly when the pressures are being reduced by surface leakage or flow into a higher stratum), the gas diffusion rate is large enough to lead to continuous but slow gas leakage.

In the fracture, once solution gas saturation is achieved, free gas at the top of the fracture develops. The gradient in gas is less than 1 kPa/m (rather than ~10.5 kPa/m for water) so there is an even greater excess driving pressure at the upper tip. In addition, this gradient effect tends to favor driving the liquid in the fracture back into the formation, albeit slowly, and the fracture becomes more and more gas-filled. Thus, there is a self-reinforcing process: the greater the vertical height of the fracture, the greater the excess driving force at the tip. The fracture grows vertically upward, and eventually leads to gas leakage behind the casing at the surface. It will migrate up around the outside of any casing strings at higher elevations because the excess pressure that can be developed at that stage is large enough to fracture even excellent bond (Figure 4). However, why does it take so long for the gas to get to surface (sometimes decades)?

Gas must migrate to surface through a circumferential fracture perhaps only 10-20 μm thick extending over only a limited part of the circumference of the rock-cement interface. Note that fracture aperture develops between p_f and σ_r ($= \sigma_3$) when the pressure acts to maintain it open, but because the rock and cement have elastic stiffness, they act to severely restrict the aperture. Thus, there are at least two rate-limiting aspects to gas evolution at the surface: diffusion rate of gas into the fracture, and the low "hydraulic conductivity" of the circumferential fracture arising because of its narrow aperture.

Why does the fracture grow so slowly? When the micro-annular circumferential fractures are not connected and are short, the excess pressure at the tip is small. Also, if the casing pressure is large because of production pressure, this leads to a small outward flexure that may be enough to maintain the fissures closed. (Note that if a "better" bond log response is desired, simply pressurize the casing as the bond log is run!) As the production pressure declines with time, the fissure will tend to open more because the casing is less pressurized. Also, fracture growth in the vertical direction is undoubtedly aided by pressure and thermal cycles.

Nevertheless, it is common for gas bubbling at the surface to be noticeable only years and sometimes decades after P&A. Over time, the effective fracture length increases, and this leads to the driving pressure increase discussed above. Because the velocity of a fracture is a very strongly non-linear process that is positively coupled to the driving pressure, it probably takes years for diffusion processes to lead to a condition where growth starts to accelerate. However, once acceleration begins, the fracture length increases, and complete upward propagation is fast (days? months?), limited only by the rate at which fluids can enter the fracture at depth and flow to the tip. Thus, before P&A, a cement bond log may show that the well is in good condition, yet this is no guarantee that, years later, leakage will not occur.

As the fracture rises, the condition that the pressure in the fracture exceeds the pore pressure in the surrounding strata will arise. This will lead to flow from the fracture out into the strata. If this flow is unimpeded, it will occur and the fracture vertical growth will terminate. Now, a condition exists where gas and liquids are entering the wellbore region behind the casing and leaving it at a higher elevation. This is a loss of zonal seal, and could have negative effects, such as pressurizing higher strata, or leakage of brines and formation fluids into shallower strata causing contamination. It can also have positive environmental effects, properly executed.

Yet, despite the existence of permeable zones, gas is still observed at the surface, and also as deep-sourced gas in shallow groundwater aquifers. The reason is probably that the cement paste in the pores of permeable strata acts to exclude gas by capillarity effects along the entire length of the stratigraphic column (it takes a large Δp to overcome surface tension effects in small pores). This means that gas must leave the fracture mainly by liquid-phase diffusion. So, it seems that in leakage cases the flow rate from depth simply exceeds the diffusive bleed-off rate at higher elevations, leading to the excess appearing at the surface. An interesting chromatographic effect probably occurs with mixed gases; because of differing pressure solubility, more soluble gases will diffuse into adjacent strata more rapidly, and the least soluble, CH_4, will arrive at the surface almost pure.

Unfortunately, even if no gas appears at the surface, it is no guarantee that the well is not leaking. In fact, the common occurrence of household water sources being charged with deep-sourced gas is clear evidence that there are many cases of leakage where the gas simply enters the water aquifer, and may never bubble around the casing.

Discussion

The hypothesis satisfactorily explains the phenomena associated with well behavior. Thus, it leads to a number of approaches to solve the problem. Eliminating cement shrinkage is one, but there are other practical solutions that are workable.

Cement shrinkage study and the development of new cement formulations that have no Portland phase[15] is an ongoing part of an industry-sponsored project, and new formulations will be available soon. Better recommendations for P&A are also being developed. These will be the subjects of other articles. This section will present an approach to environmental protection that can be operationally implemented at present.

Given that gas leak-off by Darcy flow (rather than diffusion) is likely impeded by the cement paste in the pore space of adjacent strata, one approach to environmental protection is to complete a well in the manner sketched in Figure 5. The open, non-cemented section is deliberately chosen to be across beds of sufficient permeability so that when excess pressure develops in the zone, the capillary exclusion effect can be overcome (less than 1 MPa typically, but depending on grain size and clay content). Because the rate of gas entry and transmission through the circumferential fracture is small, a permeable bed just a few 10's of centimetres thick will suffice to act as a drain. This bed will accept sufficient volumes of gas, and providing that it is laterally continuous, will act as a drain for a very long time, perhaps indefinitely.

Is there a need to revisit API standards on cement formulation, placement and completion practices, and industry quality control during placement?[16,17,18] We believe so, but this is a substantial issue, and specific suggestions await more results.

Closure

The elements of the gas leakage mechanisms that we propose are the following:

- Various mechanisms, but mainly cement shrinkage, lead to a drop in radial stress.
- When $\sigma_r < p_o$, a circumferential fracture will open.
- Differences between lateral stress gradients and pressure gradients provide forces for vertical growth.
- The excess pressure that develops at the upper leading tip increases as the (vertical) height.
- The fracture will tend to become gas filled as gas slowly diffuses into it, increasing the driving force.
- Fracture aperture is severely limited by the stiffness and geometry, limiting the upward propagation rate.
- Pore blockage because of cement paste penetration limits gas leak-off rates to those associated with diffusion because of capillarity effects.
- Eventually the fracture will rise, and gas will enter shallow strata or leak at the surface.

This working hypothesis has led to recommendations on cementing and casing strategies, and the pursuit of a cement formulation that can be easily placed yet not shrink is important, both for primary cementing, and for P&A.

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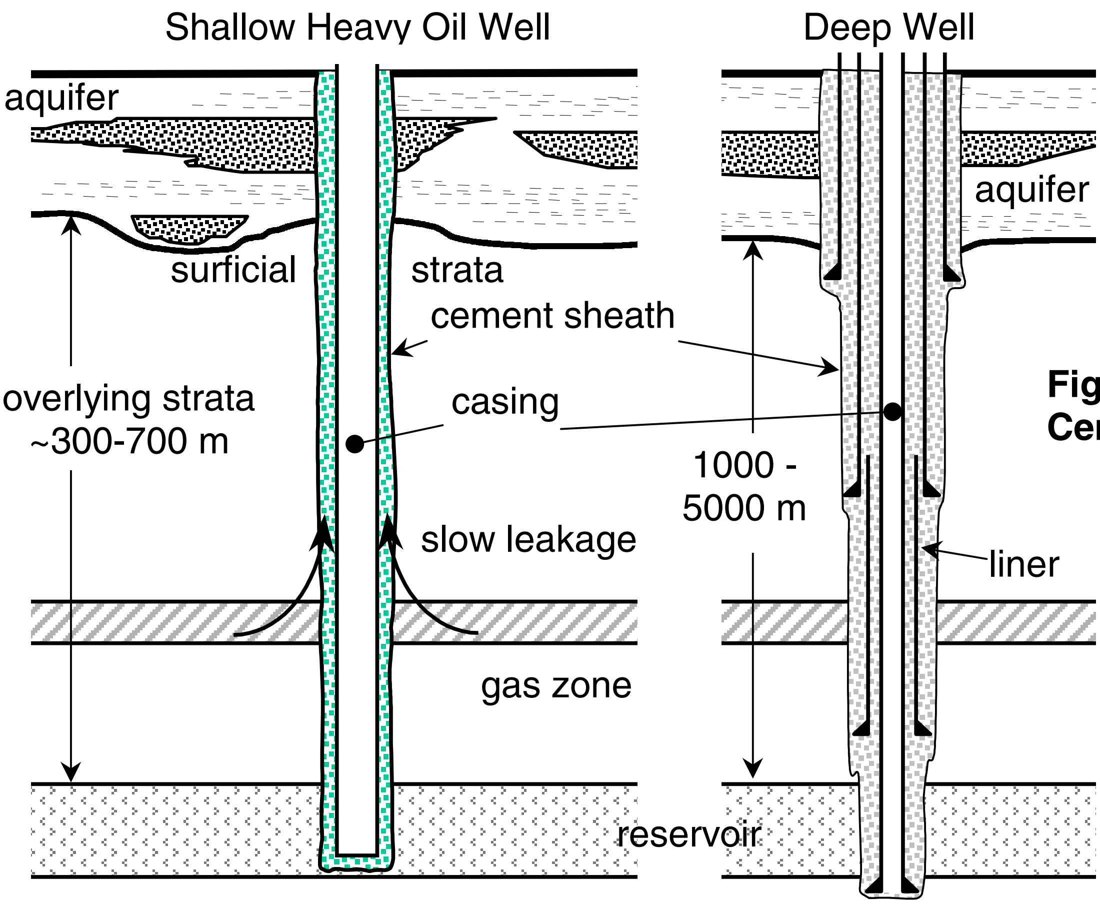
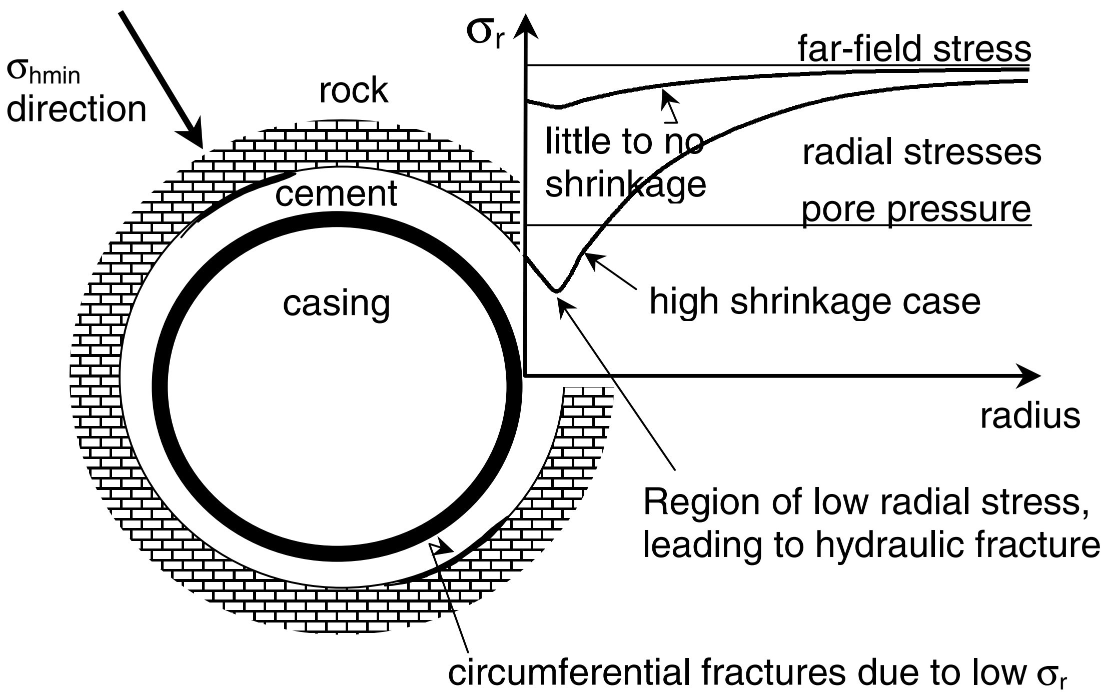


Figure 1: Cased, Cemented Wells

Figure 2: Radial Stresses and Circumferential Fractures



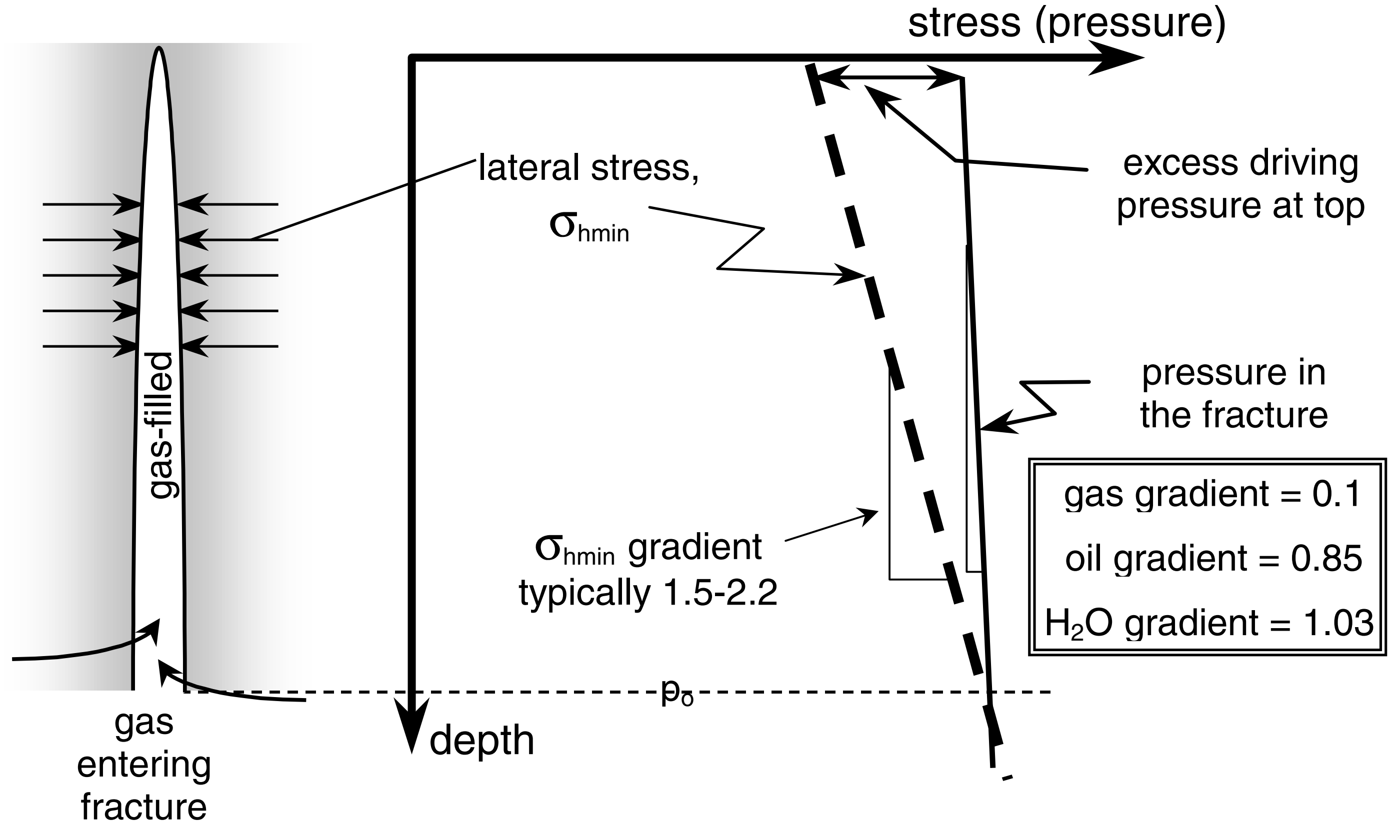


Figure 3: Fracture Driving Pressure from Gradient Differences

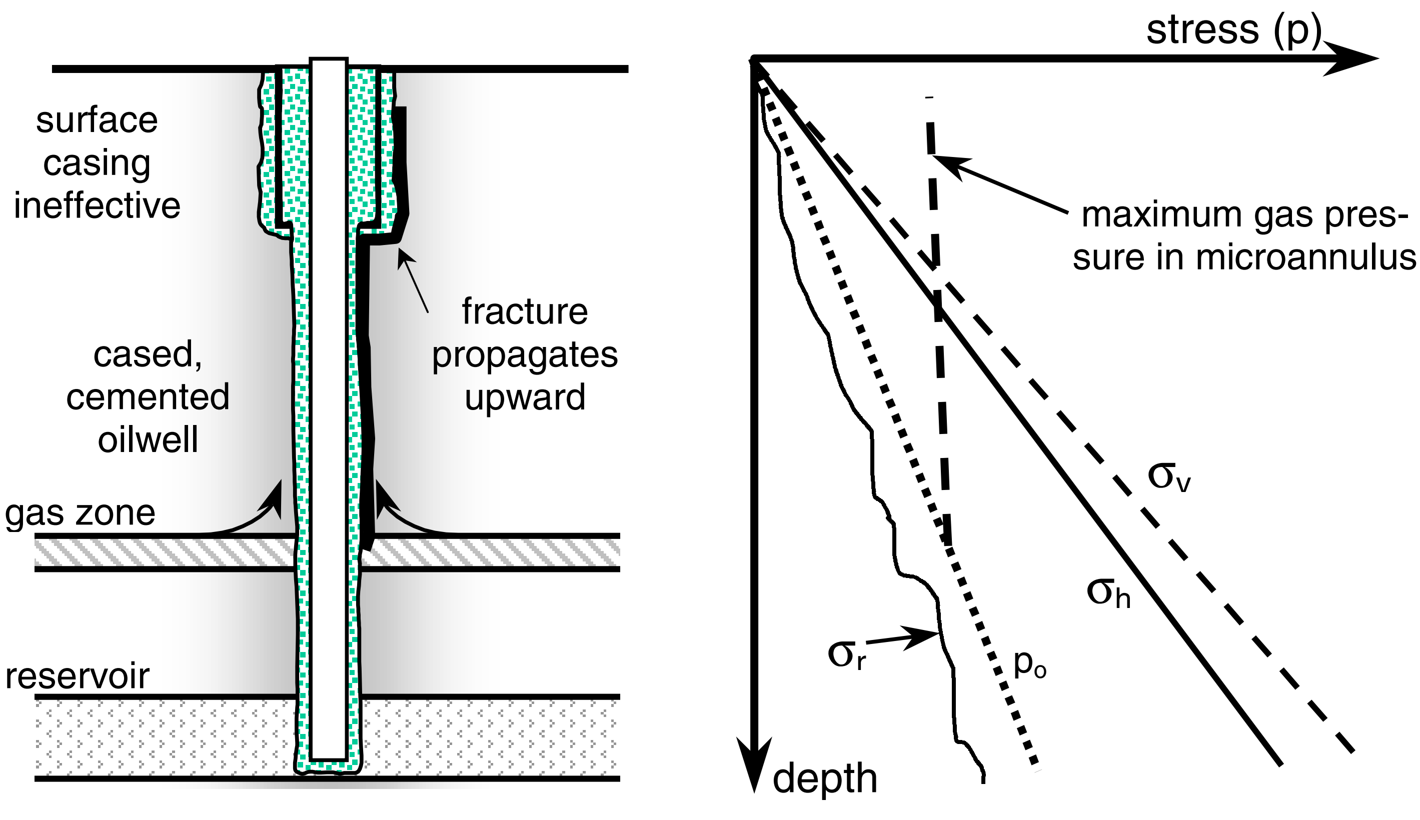


Figure 4: Fracture Approaching Surface

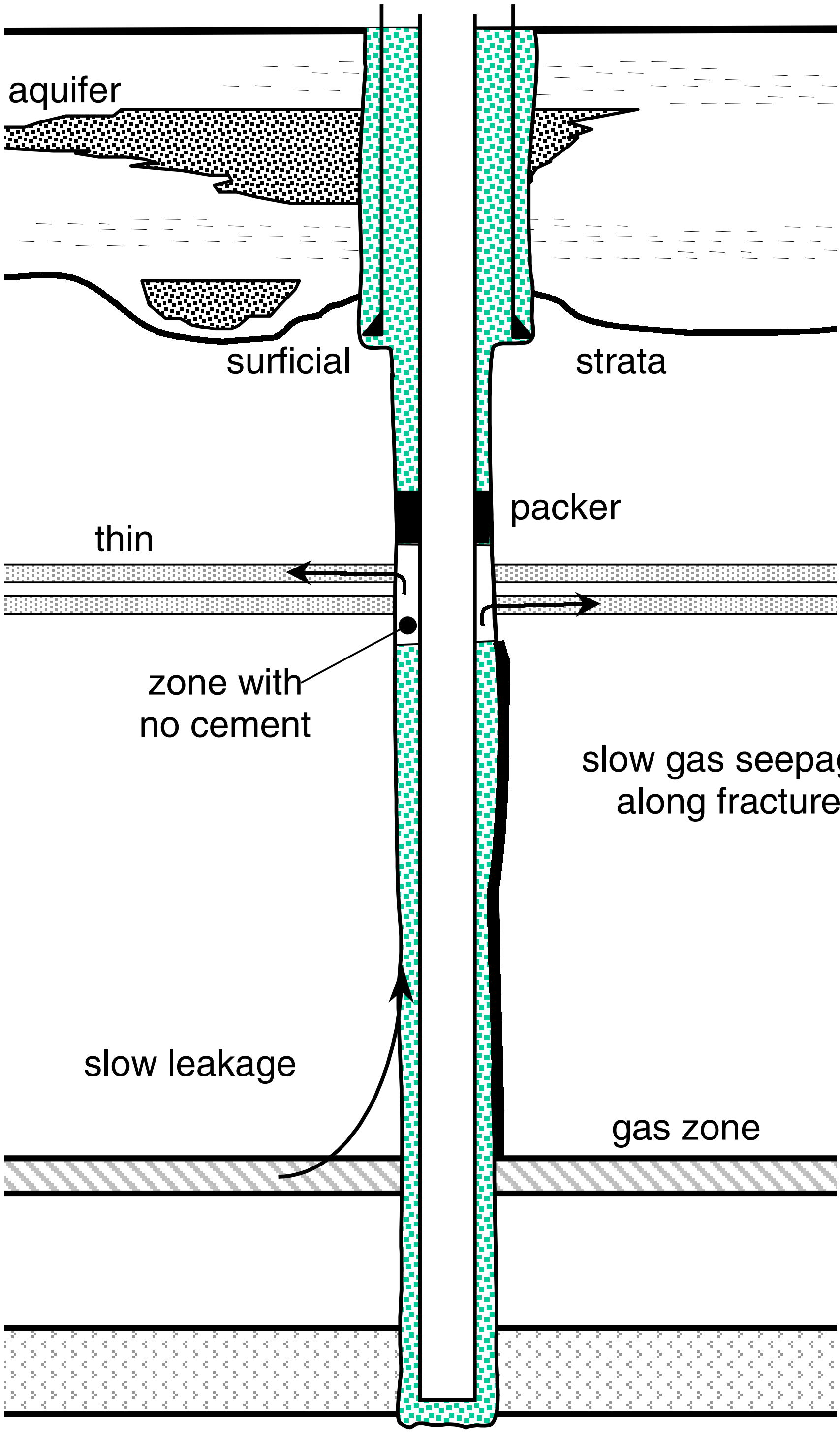
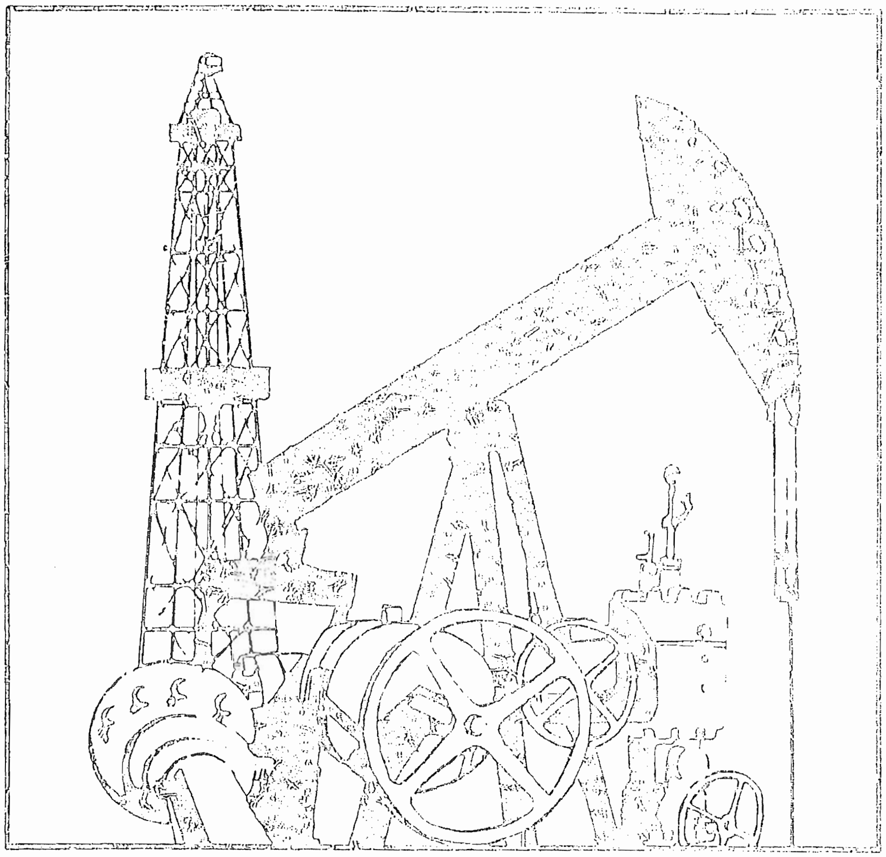


Figure 5: Leaving a Leak Off Zone to Arrest Gas Seepage

AGRICULTURAL LAND AND WATER CONTAMINATION

from Injection Wells, Disposal Pits, and Abandoned Wells used in Oil and Gas Production



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AGRICULTURAL LAND AND WATER CONTAMINATION FROM
INJECTION WELLS, DISPOSAL PITS, AND ABANDONED WELLS
USED IN OIL AND GAS PRODUCTION

Ground water makes up about 60% of all water used in Texas statewide, and a larger percentage in some areas. As development and use of ground water continues, its quality suffers unless adequate steps are taken to protect it from man-made contamination. Once contaminated, ground water may require costly cleanup measures, and may be rendered unusable. Among the potential sources of pollution from oil and gas exploration and production are injection wells used for saltwater disposal and in enhanced recovery, saltwater disposal pits used in the past, and improperly plugged and abandoned exploration, production, and disposal wells.

In response to periodic inquiries from farmers, ranchers, and other concerned individuals, the Office of Natural Resources conducted a study of this aspect of the agricultural land and water contamination problem. The research was conducted by Thomas Gorman, formerly on the staff of the Railroad Commission, Oil and Gas Division. Railroad Commission staff also provided invaluable cooperation and assistance. This report, written by Rick Piltz, summarizes the findings of the study.

Injection Wells, Disposal Pits, and Abandoned Wells

Injection Wells

An injection well is any well used to force liquids deep into the ground. Underground injection is used in the oil and gas industry for disposal of salt water that accompanies production, as well as other oil and gas waste, and in enhanced recovery operations (see Diagram 1). The Railroad Commission has permitting and enforcement authority over both types of injection wells, under federal and state law. There are approximately 50,000 injection wells in Texas associated with oil and gas production.

Federal requirements for injection-well regulation are specified in the Safe Drinking Water Act of 1974, which is administered by the Environmental Protection Agency. In the Safe Drinking Water Act, Congress recognized the need for effective state regulatory programs to protect underground drinking-water sources from contamination by injection wells. EPA's regulations list construction, permit, operating, monitoring, and reporting requirements for specific types of wells, set forth enforcement procedures, and direct the states to set up their own underground injection-control programs to protect defined drinking-water sources.

In 1980, the Railroad Commission created an Underground Injection Control (UIC) Section in its Oil and Gas Division to administer a program consistent with federal and state law. In 1982, EPA granted primary enforcement authority to the state.

Jurisdiction over injection wells in Texas is divided. The Railroad Commission regulates wells used in energy production, including oil and gas, in situ coal gasification, and geothermal resource recovery.

The Texas Department of Water Resources regulates wells used for industrial waste disposal (including hazardous waste), for mining of minerals including uranium, copper, sulfur, sodium chloride, potash, and phosphate, and for various other purposes.

Chapter 27 of the Texas Water Code (the Injection Well Act) gives the Commission jurisdiction over Class II wells injecting "oil and gas waste," which is defined to include the disposal of salt water and other produced fluids, disposal associated with the underground storage of hydrocarbons, and injection arising out of, or incidental to, the operation of gasoline plants, natural gas processing plants, and pressure maintenance or repressuring plants. The Injection Well Act authorizes the permitting of wells for the disposal of salt water by injection into formations that are not freshwater sands.

Chapter 91 of the Natural Resources Code gives the Commission jurisdiction over Class II injection wells used for enhanced recovery of oil and gas and for underground hydrocarbon storage. Enhanced recovery wells inject fluids into formations productive of oil and gas.

The Texas Department of Water Resources assists the Railroad Commission by making recommendations to the oil and gas industry and to the Commission for the protection of usable-quality ground water during the exploration for and production of oil, gas, and other minerals.

Disposal Pits

Waste-disposal pits have been used in oil-production operations to store or evaporate oilfield brines. In 1969, the Railroad Commission prohibited by rule the unauthorized use of these saltwater-disposal pits, which damage the land surface and can cause groundwater contamination. Most oilfield brines now produced in Texas are reinjected into disposal wells, almost eliminating the use of pits for saltwater storage and disposal.

In 1983, the Legislature put restrictions on saltwater disposal pits into statute. Under the law (Natural Resources Code, Chapter 91, Subchapter K), the Railroad Commission may allow use of a disposal pit on a temporary, emergency basis, or allow use of an "impervious" disposal pit.

Abandoned Wells

There are an estimated tens of thousands of abandoned and unplugged or improperly plugged oil wells in Texas. Leaks through these abandoned wells can result in groundwater contamination, rendering water unfit for human or livestock consumption. They can also lead to saltwater breakout, contaminating the land surface and reducing soil productivity.

The Legislature in 1983 enacted a $100 drilling permit fee for any permit to drill, deepen, plug back, or re-enter a well, with the permit revenues earmarked for a new State Well Plugging Fund. The Well Plugging Fund is to be used by the Railroad Commission for plugging abandoned wells and for enforcement of laws or rules in relation to the Commission's authority to prevent pollution.

The Data Base: Railroad Commission Complaint Files

Our study of cases of groundwater contamination resulting from oil and gas exploration and production activities is based on information available in the Railroad Commission's complaint files. The Commission's Field Operations Section keeps a file summarizing pending and recently closed complaints, as well as a complete file on each complaint.

The Field Operations Section handles lease inspections and complaints regarding leases. The district inspectors try to inspect each lease once a year, but this is not always possible because of personnel and budget limitations. Complaints from outside comprise the majority of the matters on which district inspectors take follow-up action.

We reviewed the summaries of all 1789 complaints that were pending as of November 1984, as well as the summaries of 2869 complaints that were closed between January 1982 and November 1984 (these were the complaints filed alphabetically between A and K, approximately one-half of the total complaints closed). The results of this review are summarized in Table 1, which indicates the frequency of the principal types of complaints to the Commission:

TABLE 1

GENERAL SUMMARY OF COMPLAINTS TO RAILROAD COMMISSION: 1982-1984

Category	Pending Complaints No. of Cases	Pending Complaints % of Total	Closed Complaints No. of Cases	Closed Complaints % of Total
Abandoned Wells	608	34.0%	361	12.6%
Water Well Problems	93	5.2	183	6.4
Saltwater Pits--active	72	4.0	195	6.8
Other Pits (drilling, workover, etc.)--active	62	3.5	189	6.6
Abandoned Wells w/ Abandoned Pits	127	7.1	96	3.3
Surface Water Pollution	56	3.1	164	5.7
Saltwater Leaks from Pipes and Tank Batteries	50	2.8	166	5.8
Gas Venting, Flaring, Leaking, Odor	56	3.1	139	4.8
Oil Spill	47	2.6	134	4.7
Drilling Mud Dumping	37	2.1	120	4.2
Saltwater Dumping	46	2.6	100	3.5
Sales and Payments	43	2.4	99	3.5
Oil and Saltwater Spill	27	1.5	105	3.7
Abandoned Pits	51	2.9	70	2.4
General Production Related (logs, proration, reporting)	48	2.7	70	2.4
Saltwater Spill	26	1.5	84	2.9
Oil Leaks	19	1.1	76	2.6
Location or Lease Clean-Up; Exposed Flowlines	35	2.0	55	1.9
Pollution--general complaints	41	2.3	48	1.7
Lease Identification	25	1.4	45	1.6
Drilling or Vacuum Service Without a Permit	26	1.5	38	1.3
Spacing	27	1.5	32	1.1
Oil and Saltwater Leak	21	1.2	37	1.3
Drilling Fluid Spill	23	1.3	34	1.2
Faulty Injection Wells	20	1.1	31	1.1
Saltwater Breakout	17	1.0	26	0.9
Leaking Saltwater Disposal Wells	6	0.3	35	1.2
Seepage	18	1.0	22	0.8
Tank Sediment Dumping	5	0.3	29	1.0
Saltwater Disposal Without a Permit	21	1.2	7	0.2
Other	36	2.1	79	2.8
Total	1789	100.0	2869	100.0

Source: Railroad Commission complaint files. Table 1 summarizes all complaints pending as of November 1984, and complaints filed alphabetically between A and K that were closed between January 1982 and November 1984, about one-half of the closed complaint summaries. The categorization of complaints was developed informally by the researcher.

Confirmed Cases of Contamination

Of the 4658 complaint summaries reviewed for this study, 97 pending complaint summaries and 90 closed complaint summaries suggested possible contamination of ground water. These complaints mainly involved water well problems, faulty injection wells, leaking saltwater disposal wells, saltwater breakout, seepage, and disposal without a permit. The full complaint files for these cases were reviewed, to the extent the files were available and could be located by the researcher.

A reading of the full complaint files in these 187 cases revealed 69 confirmed cases of groundwater and/or land contamination--36 in pending complaints and 33 in closed complaints. (Since one-half of the closed complaint summaries were reviewed for this study, it might reasonably be inferred that the Railroad Commission files for 1982-1984 contain a total of roughly 100 confirmed cases of contamination from oilfield injection wells, saltwater pits, and abandoned and improperly plugged wells).

The majority of confirmed pollution cases occurred in a relatively small portion of the state--57% of the cases occurred in two of the Commission's 12 districts, in which a high percentage of production is conducted by small independent operators (see Figure 1). A large proportion of the complaints where pollution was found concerned the operations of small independents, with only 5 of the 69 cases traced to major oil companies. Twenty of the 69 cases involved operators that were unknown or no longer in business.

Only a small percentage, about 1-2%, of the total complaints received by the Commission appear to involve groundwater contamination. However, groundwater contamination cases are often more costly and serious than cases involving other types of complaints. Groundwater complaints stemming from the pollutionof water wells are the most numerous, but saltwater breakout, though less frequent, can also be a serious problem.

Because of the numerous sources of non-oilfield related water well contamination, less than one-fifth of the water well complaints proved on inspection to be related to oil and gas activities. Frequent non-oilfield pollution problems include sewage contamination, wells completed deeper than the base of usable quality water or with improper casing, and bacteria growth in the well.

When a water well is experiencing an oilfield pollution problem (typically, high chlorides), the pollution source is often difficult to track down. The source could be a leak in the casing of a disposal well, leakage behind the casing due to poor cement bond, old saltwater evaporation pits, or, most often, transport of contaminants through an improperly plugged abandoned well. Of the 30 water well complaints reviewed in this study where groundwater contamination from oilfield activities

was found, in only two cases was the problem traced to a single injection well. Nine cases were attributed to saltwater communication between the injection zone and fresh water sands by means of improperly plugged abandoned wells. Another nine of the cases were attributed to the saltwater evaporation pits that were unrestricted in Texas before 1969.

One positive note is that, when the contamination was due to an improperly plugged well, the problem could be fixed by plugging the abandoned well properly. This procedure could cost $10,000-$20,000 in state funds in the typical case when the owner is long gone. (The average contract price for a well-plugging is $7000-$8000, but this does not include such costs as field work by district staff, attempts to identify and locate the operator, and administration).

The other major pollution problem, saltwater breakout, is closely related to water well contamination (see Diagram 2). When breakout is complained of, the inspection typically turns up a real pollution problem. Saltwater breakout takes place through an improperly plugged well completed into the injection zone. Usually these problems can be remedied, but the state often has to pay the plugging cost.

Faulty injection well complaints often concern injection down the casing, a violation of the requirement, since 1982, that the much safer tubing-packer arrangement be used in disposal wells (see Diagram 1). Regular inspections and pressure tests are the best way to insure proper functioning of injection wells. Since 1982, Underground Injection Control permit regulations have required annual well-monitoring reports to the Commission, and pressure tests on disposal and secondary recovery wells every five years. The operator monitors injection volumes and injection pressure with a monthly reading, and reports annually to the Railroad Commission, which does an annual inspection. The operator is exempted from the five-year pressure-test requirement if he reports the monthly annulus pressure of the well. When Commission district inspectors do go onto a lease and monitor pressure-tests of injection wells, they sometimes find casing leaks. For example, in one case when inspectors looking for the source of an oil seep tested several injection wells, they found casing leaks in two of the six wells tested.

The other groundwater pollution problem, seepage (see Diagram 2), is found to be oilfield-related in only a small percentage of cases. In four of the six cases when oilfield-related seepage was found, it involved wells that had not been properly plugged, through which the communication was taking place. In the other two cases, the seepage was due to single disposal wells. In those cases, the seep was stopped by reworking or shutting-in the well. However, since seepage can travel some horizontal distance, it may be difficult to confirm the origin of the problem.

Diagram #1

Injection Well with Tubing and Packer

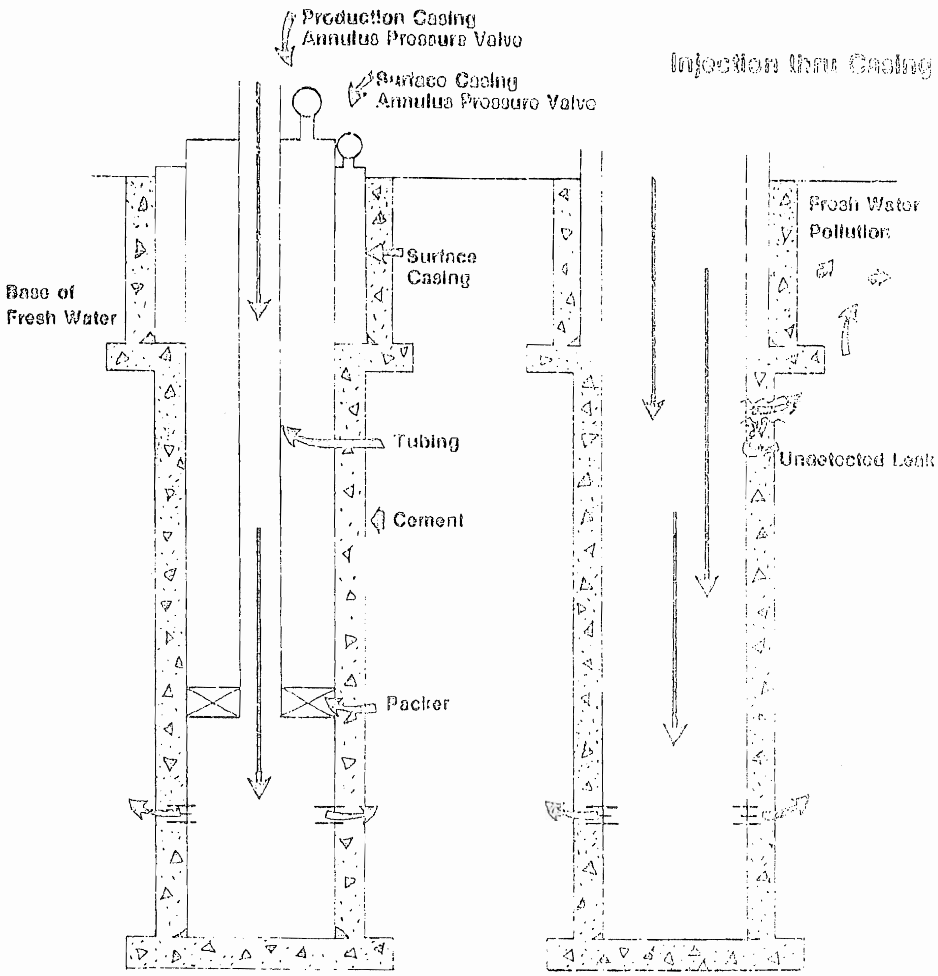
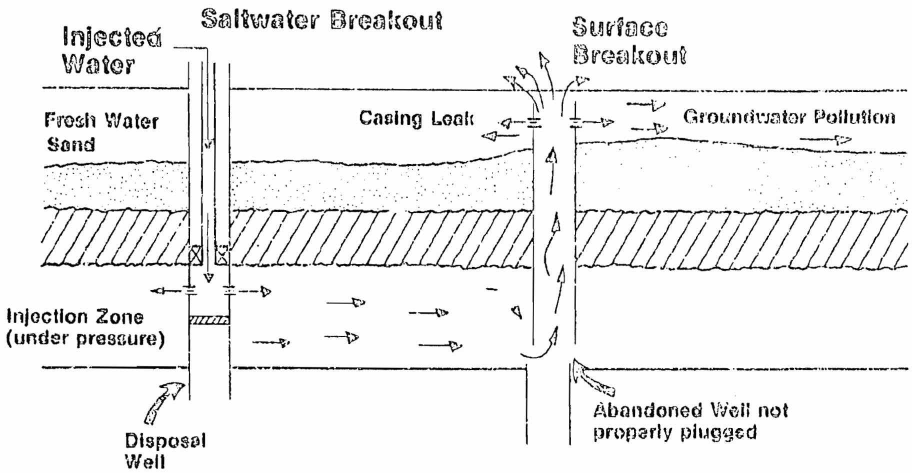
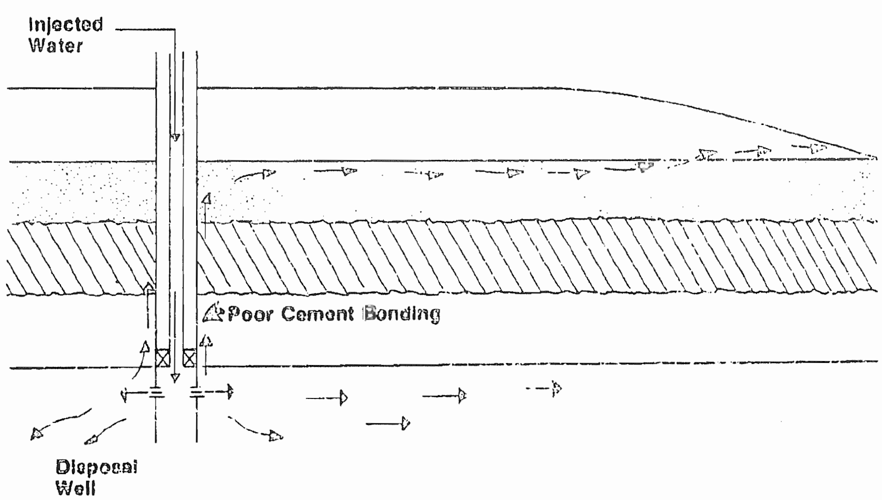


Diagram #2



Seepage



Concluding Observations

Our review of the available evidence indicates that most of the problems of groundwater contamination resulting from oil and gas production activities stem from unsound past practices that are no longer permitted: abandoned and improperly plugged wells that are frequently not a part of the public record, saltwater disposal pits, and saltwater disposal down the casing of an injection well without a tubing-and-packer arrangement. These practices have left a legacy of pollution that will continue for some time into the future, and that has implications for current public policy. In particular, the fact that thousands of abandoned wells are still being discovered should be considered in decisions regarding funding of the state's well-plugging program, and in regulation of deep-well injection of hazardous wastes.

The State Well-Plugging Program

About 40,000 drilling permits are applied for annually in Texas, which generates $4 million in annual revenue for the Railroad Commission's State Well-Plugging Fund. When it receives a complaint and discovers an abandoned well, the Commission tries to locate the last operator or a working-interest owner, and do an enforcement action. If the operator can't be found, or has gone bankrupt, and no other responsible party can be found who is able to plug the well, the state will use the Well Plugging Fund. At present, the Commission has identified 1600 leases with potentially troublesome abandoned wells, a total of some 3000 abandoned wells altogether, and is checking to see how many can be plugged by operators or working-interest owners, and how many the state will have to plug. (A surface operator, such as a farmer or rancher, who did not receive any financial benefit from the well, is not liable.)

The apparent scope of this problem, combined with the serious threat posed by contamination of agricultural land and water resources, suggest that continued adequate funding for the State Well-Plugging Fund should be strongly supported.

Hazardous Waste Management

Much of the technology for constructing and operating injection wells used in oil and gas production has been transferred to wells used for deep-well injection of hazardous chemical wastes. Although this technology is well-established, faulty construction, improper operation, or deterioration of a well could lead to a failure of the hazardous waste injection procedure. There could be several potential contamination pathways resulting from a failure, such as upward migration of the waste liquid from the receiving zone along the outside of the well casing, escape into potable aquifers due to well-bore failure, and vertical migration and leakage through abandoned or improperly plugged wells in the vicinity.

A 1983 report by the Congressional Office of Technology Assessment noted that:

> upward migration of waste through abandoned or closed wells is particularly insidious because regions where waste injection is widely practiced also have a long history of energy exploration and development. Depending on the site geology, these wells provide vertical connections from deeper formations to near surface or surface formations. Many of these wells were drilled before plugging of abandoned wells was required. Often, their locations are not known and some may no longer be evident at the ground surface.

Hazardous waste injection well regulations require potential disposers to calculate the subsurface area expected to be affected by the pressure of waste injection. Before new waste injection can begin, the operator is required to survey and to plug existing wells within this area. The findings of our study suggest the state should be very cautious regarding the siting of hazardous waste injection wells in areas with a history of oil and gas exploration. If such siting is permitted, it should be done, among other requirements, only after a survey of the area to locate abandoned wells is conducted using the highest standards for precision and accuracy.

Examples of Groundwater Contamination Problems

The following partial listing of case summaries through November 1984 illustrates some of the problems brought to the attention of the Railroad Commission:

Water Well Problems

Hockley County, June 1982. Saltwater contamination in water wells was found to be caused by old disposal pits.

Clay County, October 1984. Complaint that unplugged well was making water wells go salty. Investigation found abandoned well, which was ordered plugged.

Ward County, May 1983. Water well was found to be contaminated as a result of problems with a saltwater disposal well and saltwater pits. The pits were backfilled and the well was plugged.

Clay County, June 1984. Complaint of water well contamination by nearby injection well. Investigation showed high chloride content in the well water, and casing problem with the injection well. Attempts to repair the casing proved unsuccessful, so the well was ordered plugged.

Hockley County, July 1984. Complaint of high chloride content in domestic water well. Investigation showed the problem was probably caused by an old saltwater disposal pit used until 1966.

Andrews County, July 1984. Unusually high chloride concentration found in water well. District personnel suspect old improperly plugged well nearby.

Midland County, August 1984. Analysis of water well sample showed a very high chloride concentration. The well is near the site of a previous complaint where it was determined that high chloride concentrations were caused by old backfilled saltwater pits.

Runnels County, March 1983. Unusually high chloride concentration found in water well. District personnel suspect a nearby abandoned well that was not properly plugged.

Schleicher County, September 1984. Good water well developed high chloride concentration. District office plans to request state funds to plug old abandoned well one-quarter mile away.

Scurry County, October 1982. High chloride concentrations in several water wells proved to be from several saltwater pits that had been used in the recent past. Chloride concentrations decreased significantly after the pits were backfilled.

Marion County, November 1984. High chloride concentration found in water well located 1000 feet from one injection well and 2000 feet from another. Commission is investigating the injection wells.

Saltwater Breakout

Callahan County, November 1982. Saltwater breakout was found to result from a well that had been re-entered for injection use. The well had been plugged originally in 1954. The well was re-plugged in 1983.

Wichita County, April 1982. Saltwater breakout problem was found to be due to a leaking injection well, which the operator was ordered to repair.

Throckmorton County, April 1984. Saltwater breakout found to be due to an abandoned well. Well had to be plugged with state funds.

Wichita County, December 1983. Investigation found salt water to be surfacing apparently as a result of breakout from an old well. Inspection also found unlined pits, abandoned wells, and no lease identification. The state spent $16,000 to plug six abandoned wells.

Shackelford County, September 1982. Complaint of saltwater breakout from injection well. Inspection found casing leak in injection well, which was repaired.

Palo Pinto County, July 1984. Investigation found oil and salt water coming up through an improperly plugged well. The water was coming from an injection well one-half mile away. The abandoned well was plugged with state funds.

Wichita County, February 1984. Oil and saltwater breakout found to be coming from an abandoned well. The well was to be plugged with state funds.

Archer County, December 1983. Salt water found to be surfacing from a saltwater disposal well. Disposal was discontinued in the leaking well until it could be reworked.

Wichita County, July 1983. Investigation showed saltwater breakout about 100 feet from a saltwater disposal well. The unidentified well through which the breakout was occurring was plugged with state funds.

Callahan County, May 1984. Inspection found leaking abandoned well causing saltwater breakout. Well was plugged with state funds.

Archer County, July 1983. Inspection revealed numerous unplugged wells and saltwater breakout. Commission required operator to plug the problem wells.

Archer County, November 1983. Injection of salt water into an unauthorized well caused saltwater breakout on adjacent property. Commission ordered injection stopped and well to be plugged.

Faulty Injection Wells

Stephens County, June 1982. Investigation of complaint found injection well not equipped with tubing and packer. Pressure test showed a leak in the casing. The well was reworked to bring it into compliance.

Gray County, January 1982. Gulf Oil enhanced recovery injection wells were found to be the source of groundwater pollution. Gulf spent $460,000 plugging abandoned wells and testing and repairing casings, and agreed to supply the complainant with an alternative supply of fresh water. In the end, Gulf's waterflood authority was rescinded.

Glasscock County, February 1984. Saltwater disposal well had to be plugged after a hole in the 4 1/2-inch casing was found.

Wichita County, October 1984. Complaint that operator was injecting saltwater down the casing, causing possible saltwater breakout. Operator was ordered to disconnect the injection until a proper tubing and packer arrangement was completed.

Jack County, April 1984. Complaint that saltwater was surfacing as a result of excessive injection. Inspection found saltwater surfacing between production and surface casing of an offset well. The operator's injection well was ordered shut-in to see what effect it would have on the offset well.

Wichita County, October 1984. Inspection found an inactive disposal well set for injection down the casing, and an active, through-tubing injection well seeping saltwater around the casing. The lease was sealed until it is brought into compliance.

Seepage

Shackelford County, October 1983. Investigation showed oil and salt water seeping into a stock tank. The seep stopped shortly after a nearby well was plugged.

Wichita County, October 1983. Saltwater seep was found to be due to an improperly plugged well, which allowed communication of fluids from three nearby injection wells. The well was replugged and the problem appeared corrected.

Caldwell County, March 1984. Investigation showed oil, gas, and mud surfacing from an abandoned wellbore and abandoned drilling pits. The pollution was stopped when the wellbore was plugged and the drilling pits were covered, at a cost of $19,000 in state funds.

Young County, February 1984. Saltwater surfacing near a residence was found to be due to an abandoned well. The well was plugged at a cost of $15,000 in state funds.

Howard County, June 1984. Seep area found in pasture near injection wells. The well identified as the probable cause of the problem is scheduled for plugging.

Mitchell County, April 1984. Investigation found saltwater flow to surface in pasture. After the injection well on the lease was reworked, the seep stopped.

Illinois Oil Field Brine Disposal Assessment

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
WATER QUALITY MANAGEMENT PLANNING

Staff Report

ILLINOIS OIL FIELD BRINE DISPOSAL ASSESSMENT

STAFF REPORT

ILLINOIS ENVIRONMENTAL PROTECTION AGENCY
208 WATER QUALITY MANAGEMENT PLANNING PROGRAM

PLANNING AND STANDARDS SECTION
DIVISION OF WATER POLLUTION CONTROL
2200 CHURCHILL ROAD
SPRINGFIELD, ILLINOIS 62706
NOVEMBER, 1978

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FOREWORD

The study described within was initiated January, 1978 as part of the statewide 208 Water Quality Management Planning Program. Funding was provided in part by the U.S. Environmental Protection Agency under provisions of Section 208 of the Federal Water Pollution Control Act Amendments of 1972 (PL 92-500), as amended.

Contractual assistance was provided by the Illinois State Geological Survey (I.S.G.S.). Particular recognition should be given to Mr. George Lane of the Department of Mines and Minerals for his substantial cooperation and assistance in this effort, to Mr. Philip Reed of the I.S.G.S. for assisting in the acquisition, compilation and interpretation of field data, and also to Mr. Craig Murphy of Northern Illinois University for technical assistance and his many hours of fieldwork expended throughout the summer.

INTRODUCTION

This study of environmental problems related to oil field brine disposal in Illinois began in January 1978, as part of the Illinois statewide 208 water quality management planning program, and is scheduled to be completed by the end of 1979. The preliminary findings and recommendations contained herein are based on information collected and analyzed through August 1978. The format reflects the approach taken in gaining an understanding of brine related problems and in developing recommendations for their abatement. A glossary of terms appearing in this report is provided at the end of the text.

Initial Inquiries and Study Objectives

The oil field brine disposal study was initiated by the Illinois Environmental Protection Agency (Agency) after receiving several complaints from affected landowners concerning contaminated water supplies and damaged land. The majority of complaints initially received were channeled through the public participation Regional Advisory Committee serving the southeast central portion of the state. To obtain further information on brine disposal, "Problem Report Forms" were made available to interested citizens. These forms were designed to provide preliminary estimates of the areal extent and nature of problems commonly associated with brine disposal operations. Subsequent press releases soliciting the help of concerned citizens generated considerable

interest, resulting in the submission to the Agency of 16 completed forms. An example of the circulated form appears in Appendix A. The information thus collected helped provide the basis for initial investigations described in this report.

Major objectives outlined for the study included:

1. Providing an assessment of the nature and extent of environmental problems emanating from oil field brine disposal practices in Illinois.

2. Conducting a detailed field study of more specific problems related to brine disposal, in particular the subsurface migration of chloride bearing waters.

3. Providing an assessment of the efficacy of the rules and regulations governing the disposal of oil field brines in Illinois.

Information on regional geology, soil types and hydrogeology of the affected areas, as well as information on contaminant characteristics were obtained by researching previous work. It was found that a great amount of information on Illinois oil field brine and brine disposal had been compiled by the Illinois State Geological Survey (ISGS).

To employ this expertise, the Agency entered into a contract with the ISGS for a detailed field investigation of four typical brine disposal sites in south central and southeast central Illinois. The primary

purpose of the field study was to develop a reliable and convenient methodology for identification of chloride concentrations in water-bearing earth materials.

Twenty-three piezometers were installed during the months of June and July 1978 to facilitate development of a relationship between ground water quality (chloride concentration) and apparent resistivity. Geologic descriptions of the sites, cross sections with gamma logs, and water level maps from piezometer observations were also developed to aid in the assessment of oil field brine disposal pollution problems.

Origin of Oil Field Brine

Identifying the origin of brine in the Illinois Basin is a complex problem. Researchers have yet to agree upon a solution. Details of the more widely accepted hypotheses are technically far beyond the scope of this report. However, for descriptive purposes, the most simplistic hypothesis will be presented here. It proposes a derivation from original sea water with a minor contribution of fresh water (Graf et al. 1966). Even though the brines originated from sea water initially incorporated in the sediment, subsequent compaction and chemical alteration resulted in concentration of the constituents. For comparative purposes, the surface water closest in composition to these subsurface brines is that of the present day Dead Sea.

Table I provides a comparison of the common constituents and typical concentrations of sea water and oil field brine (Reid et al., 1974).

Table I. Comparison of Sea Water and Oil Field Brine

	Sea Water (mg/l)	Oil Field Brine (mg/l)
Na^{+1}	10,600	12,000-150,000
K^{+1}	400	30 - 4,000
Ca^{+2}	400	1,000-120,000
Mg^{+2}	1,300	500- 25,000
Cl^{-1}	19,000	20,000-250,000
Br^{-1}	65	50 - 5,000
I^{-1}	0.05	1 - 300
HCO_3^{-1}	--	0 - 1,200
SO_4^{-2}	2,700	0 - 3,600

As indicated in Table I, brine salinity is primarily a function of the sulfates (SO_4^{-2}), bicarbonates (HCO_3^{-1}), and chlorides (Cl^{-1}) of the cations sodium (Na^{+}), calcium (Ca^{+2}) and magnesium (Mg^{+2}) (Reid et al., 1974). As a point of reference, the maximum allowable concentration for both chloride and sulfate in ground water, as set by the Illinois Pollution Control Board (IPCB, 1977), is 250 milligrams per liter (mg/l).

A feature of the underlying geology known as the Illinois Basin covers approximately 135,000 square miles of the south central and southeastern portions of the state and extends into southwestern Indiana and western Kentucky (Figure 1). Most of Illinois oil and brine production is concentrated along structural features within the basin

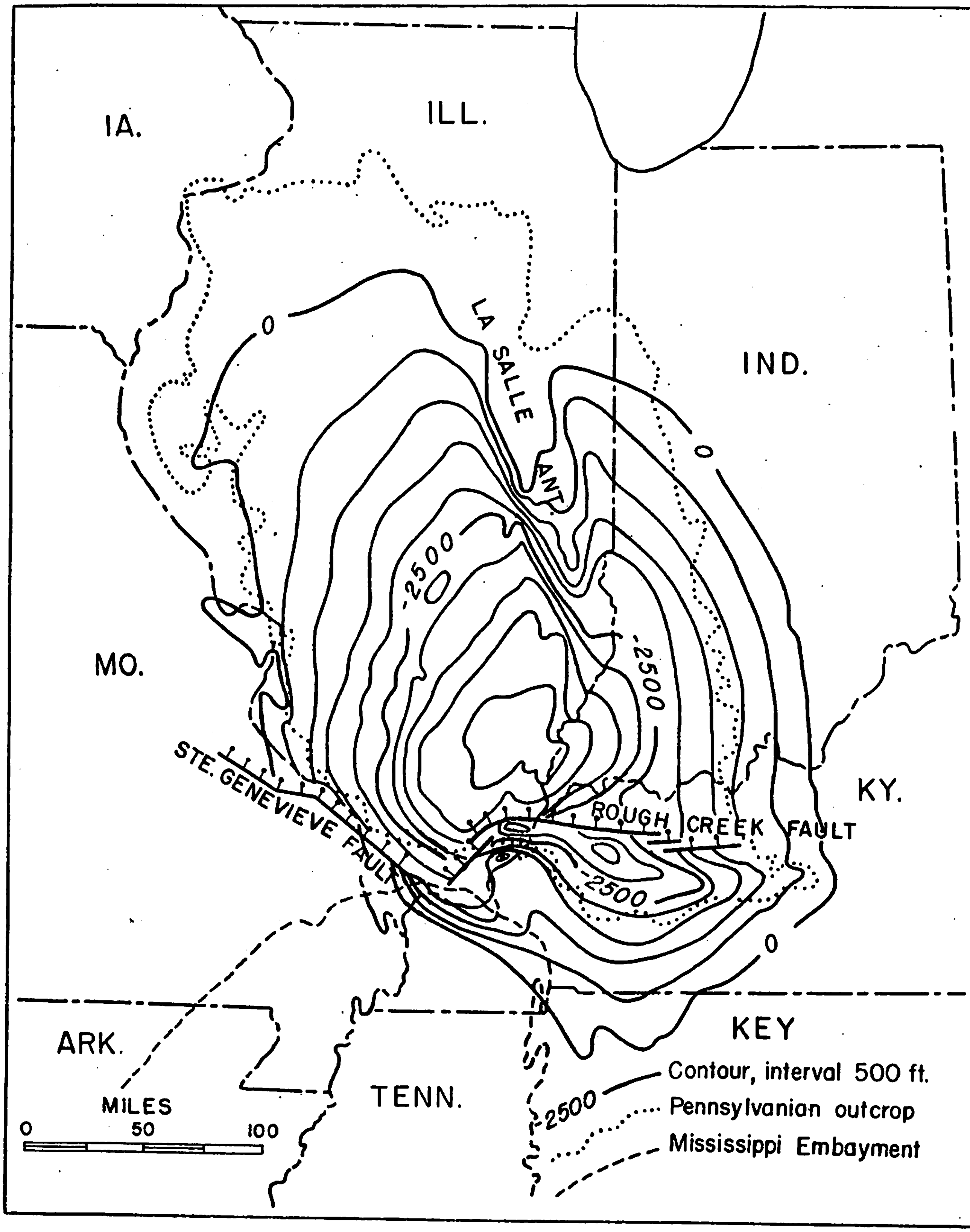


Figure 1.--Geologic structure of Illinois basin drawn on base of New Albany black shale (from Meents et al., 1952)

(Figure 2), although reef deposits also act as reservoirs for hydrocarbons.

Studies on the concentrations of total solids present in Illinois Basin brine reveal that the greatest concentrations are centrally located within the Basin. As reported by Meents and others (1952), concentrations diminish radially outward and seem to conform to the contours of the Basin. Figure 3 displays the distribution of concentrations found in samples retrieved from the Ste. Genevieve formation. Total solids in other basin formations vary slightly but all seem to exhibit similar structural dependencies.

Oil Production

The first oil fields of Illinois were discovered around 1903 in Lawrence and Crawford Counties along the La Salle Anticlinal Belt. Since the period of peak production from these oil fields in 1910, annual production has fluctuated drastically with changes in economy and technology. A peak in annual oil production of 146.8 million barrels resulted from the post-1937 Mississippian discoveries (Mast, 1970). Since then, rates have decreased to 26.3 million barrels according to 1976 statistics of Van Den Berg and Lawry (1976).

Fluid Injection

In an attempt to increase crude oil yield, numerous secondary recovery operations have been employed in the Illinois fields with

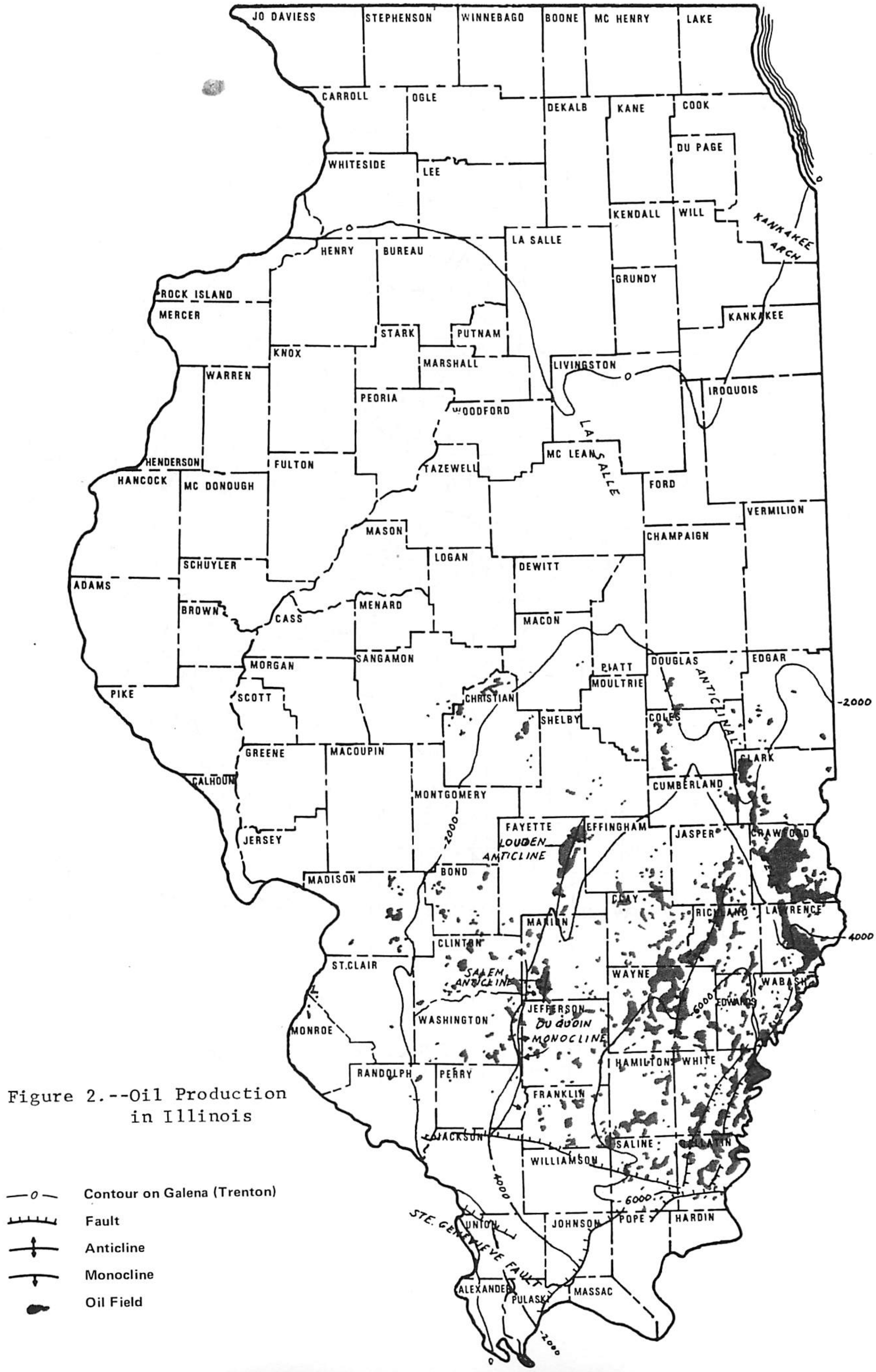


Figure 2.--Oil Production in Illinois

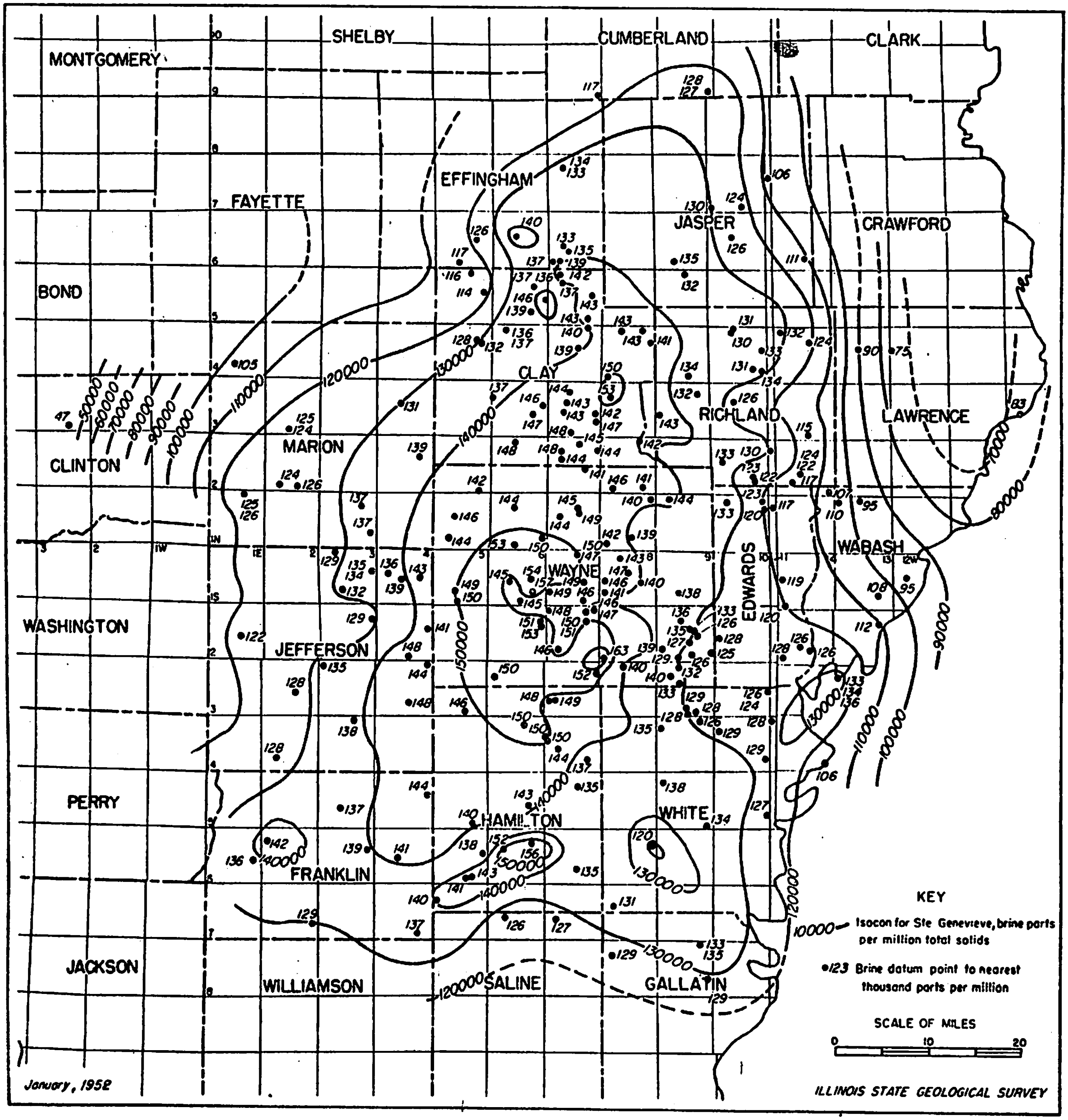


Figure 3.—Isocon map of Ste. Genevieve brines (from Meents et al., 1952).

varying degrees of success. These installations facilitate the injection of water into oil-bearing strata via input wells and are termed waterfloods. In this method, surface and subsurface waters are utilized to repressurize and flush-out oil-bearing formations. Little effect was made on the annual oil production by the early waterfloods of the 1930's. However, in the early 1950's, the combined effects of modern waterflood and hydrofracing techniques increased the total annual oil production by approximately 35 percent over production yields obtained prior to the use of these techniques.

Quite similar to waterflood installations are salt water disposal (SWD) wells. In the field, it is difficult to distinguish between the two operations. As both are injection operations, the difference lies in the final destination of the injected fluid. Unlike the fluids of a waterflood operation, the saline waters injected into an SWD well do not stimulate oil production. Rather than being reinjected into the producing formation, the brine is injected into a porous non-oil-bearing formation. To facilitate reinjection, wells drilled specifically for SWD or wells which have been converted from other functions are utilized.

Detailed information on waterflood and SWD operations may be obtained from the Illinois State Geological Survey's annual publication (Van Den Berg and Lawry, 1976).

It has been reported (Bell, 1957) that, with early oil field brine disposal practices, brine was often siphoned from an earthen holding pond directly into a cased well. Since gravity was the only injection force utilized, this type of facility was usually abandoned as the permeability

of the receiving formation diminished to a point where free flow was restricted. This posed no particular problem in that another well in the proximate area could generally be found and readily converted to meet the disposal needs. In subsequent years, technology progressed as did the amount of brine produced. With the development of the more modern secondary recovery techniques, injection pressures on the order of several hundred pounds per square inch were commonly applied, thus dramatically increasing the ultimate capacity of a typical injection well.

Some of the more serious problems involved in these disposal operations are due to the relatively high density and corrosiveness of oil field brines and their damaging effects upon land and water quality. These problems can be compounded by the fact that as an oil field matures the ratio of brine to oil may increase substantially. In fact, it is not uncommon for brine to oil production ratios to exceed 80:1. The effects of this amount of brine production can be very destructive unless oil well operators are equipped to safely dispose of or reinject these large quantities of caustic waste.

As calculated from 1976 statistics, Illinois oil fields subject to waterflooding produce an approximate average of 19 barrels of brine per barrel of oil recovered. The annual disposal rate for waterflood operations in Illinois during 1976 was 355,059,000 barrels, a 3.5 percent increase over the 1975 rate. This amounts to an average daily brine injection rate of nearly one million barrels of brine. In addition to reinjection for waterflooding, substantial quantities of brine are injected into salt water disposal wells, which in 1976 accounted for

approximately 20 percent of the new injection wells. However, there are no records available indicating the amount of brine disposed of by this method.

Brine Pollution

The highly saline waters associated with oil production pose a threat to water and land. The daily disposal of approximately 973,000 barrels of brine in Illinois has been responsible for the sterilization of thousands of acres of productive land, 3,000 recorded acres in White County alone (Fasig, personal communication). Reports from individuals indicate that oil field brine has also been responsible for the sickness or loss of numerous animals.

The Illinois Pollution Control Board (IPCB) Regulations, Chapter 3, Part II, Section 207, prescribe quality standards for underground waters of the state. Table II lists these maximum allowable contaminant levels.

Table II. IPCB Water Quality Standards

	Ground Water	General Use Surface Water
Chloride	250 mg/l	500 mg/l
Sulfate	250 mg/l	500 mg/l
Total Dissolved Solids	500 mg/l	1,000 mg/l

By comparing the constituent concentrations found in brine pits at the four study sites with the maximum allowable chloride levels set by the IPCB, it is apparent that one barrel of brine possessing a chloride concentration of 40,000 mg/l would be theoretically capable of elevating the chloride concentration of over 160 barrels of fresh water above the maximum allowable contaminant level.

Since the discovery of large commercial supplies of oil in southern Illinois in the 1930's, brines from oil fields have been disposed of in various ways. Initially, direct discharge into streams was the most common method of disposal (Reed, 1978). Later, in the 1940's, the development of injection wells allowed the oil field brine to be reinjected into compatible underground reservoirs. Perhaps the most common practice was to pump the brine into a holding pond, as this was believed to allow the brine to evaporate into the atmosphere. However, in Illinois where permeable materials are often near the surface, many brine holding ponds actually became infiltration ponds (Roberts and Stall, 1967). Consequently, although the surface water pollution problem was greatly improved through the use of holding ponds, a problem of ground water pollution is now present in many Illinois oil fields (Reed, 1978). However, this is not to imply that streams in the oil production areas have been completely unaffected since the 1940's. Oil field brines slightly diluted by precipitation, after entering the ground water system (Figure 4), can eventually be discharged into nearby streams. Flemal (1978) has reported that Illinois surface waters in areas of petroleum production may be receiving significant amounts of ground water brines.

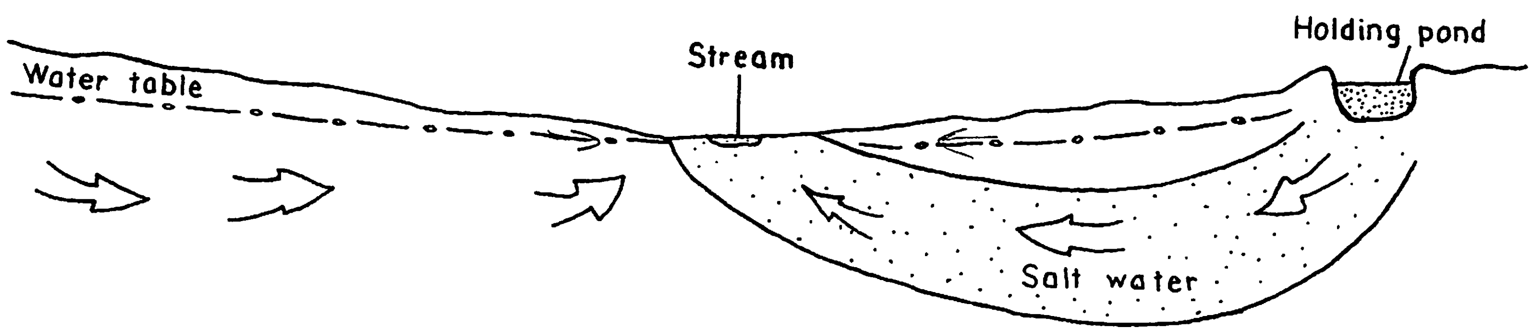


Figure 4.--Generalized movement of water in the vicinity of holding ponds (from Reed, 1978).

In addition to raising the concentrations of many chemical constituents of local ground water far above the maximum contaminant levels set by the IPCB, many of the brine holding ponds in central and southern Illinois are responsible for vegetation kills covering a limited area generally of a few acres or less. These vegetative kills are discernable from the ground and from aerial photographs, as can be seen in Plates 1 through 5 of the four study sites, shown on the following pages.

Brine-polluted ground water may eventually infiltrate public or private water supplies, or percolate to the surface. Water supplies for farms and dairy operations can become saline, leaving cattle and a family without potable water. This was the case for a Clinton County dairy farmer and his family in 1976, when highly mineralized waters infiltrated his local ground water supply (Case I - Appendix B).

Productive farm land can be left completely unvegetated as can be seen at a site in south central Bond County. In this case a field adjacent to a brine pit was left void of vegetation after saline ground water percolated to the surface (Case II, Appendix B).

Property values can drop as a result of threatened ground water contamination. This occurred in 1977 at a housing development located near a brine pit in Rochester, Illinois, after elevated chloride concentrations were found in the surrounding ground water (Case III, Appendix B). These are just a few examples of environmental degradation through brine pollution that have occurred in Illinois over recent years.

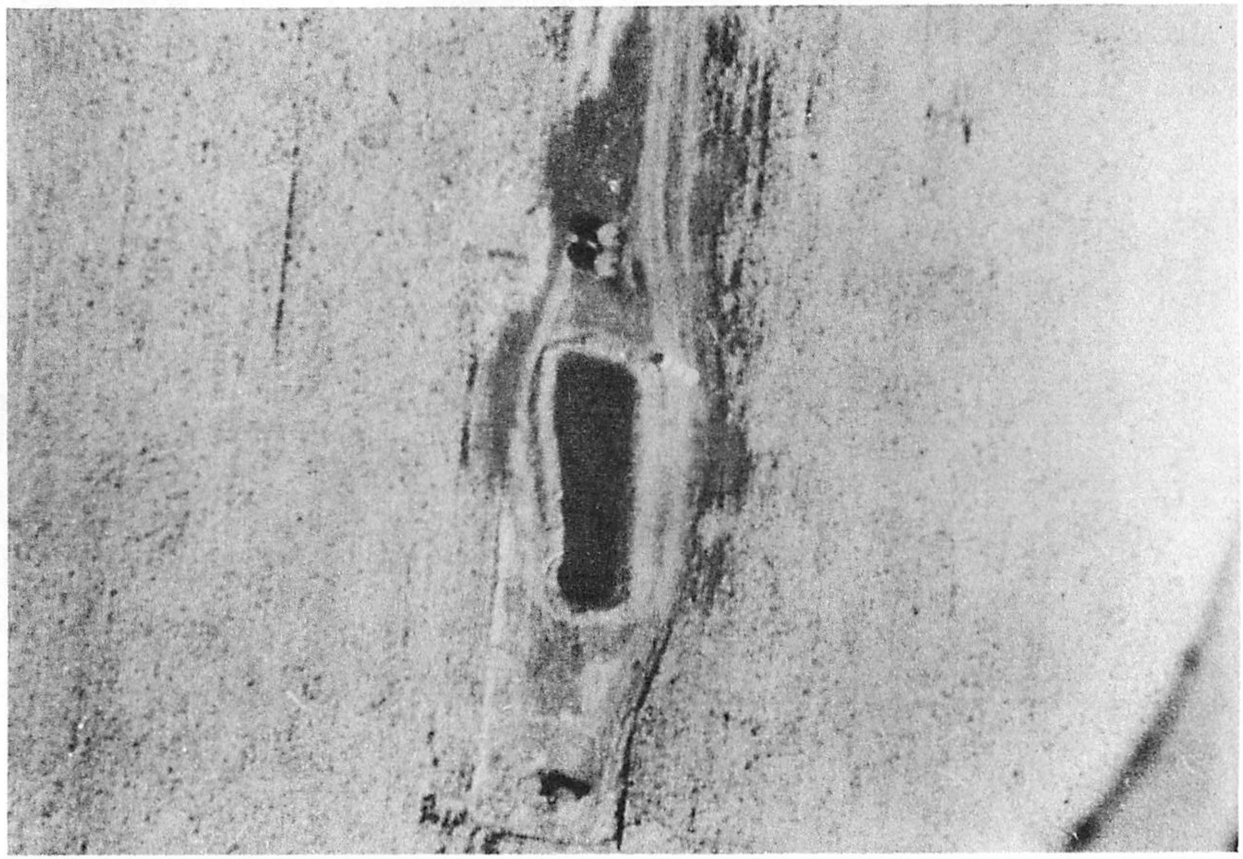


Plate 1.--Christian County Study Site

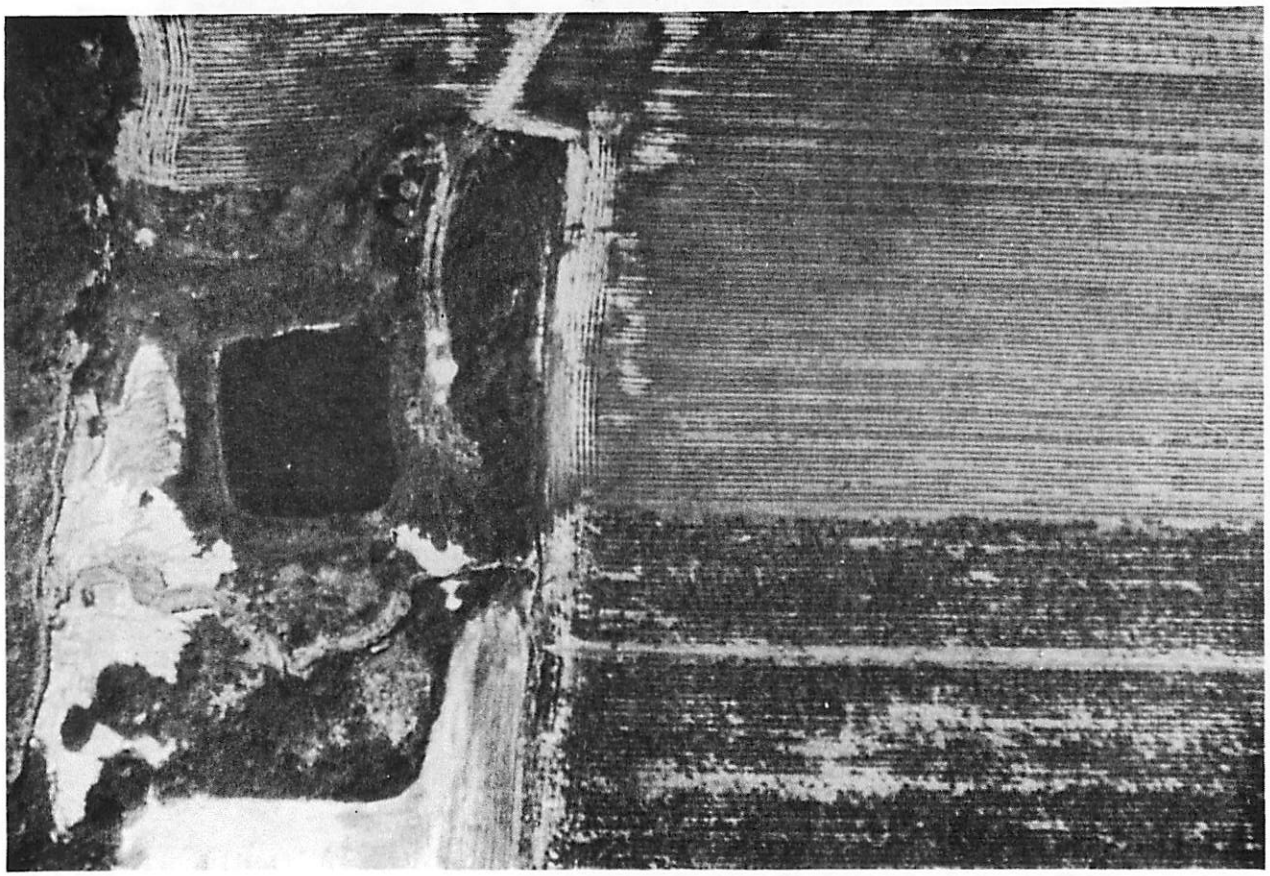


Plate 2.--Bond County Study Site

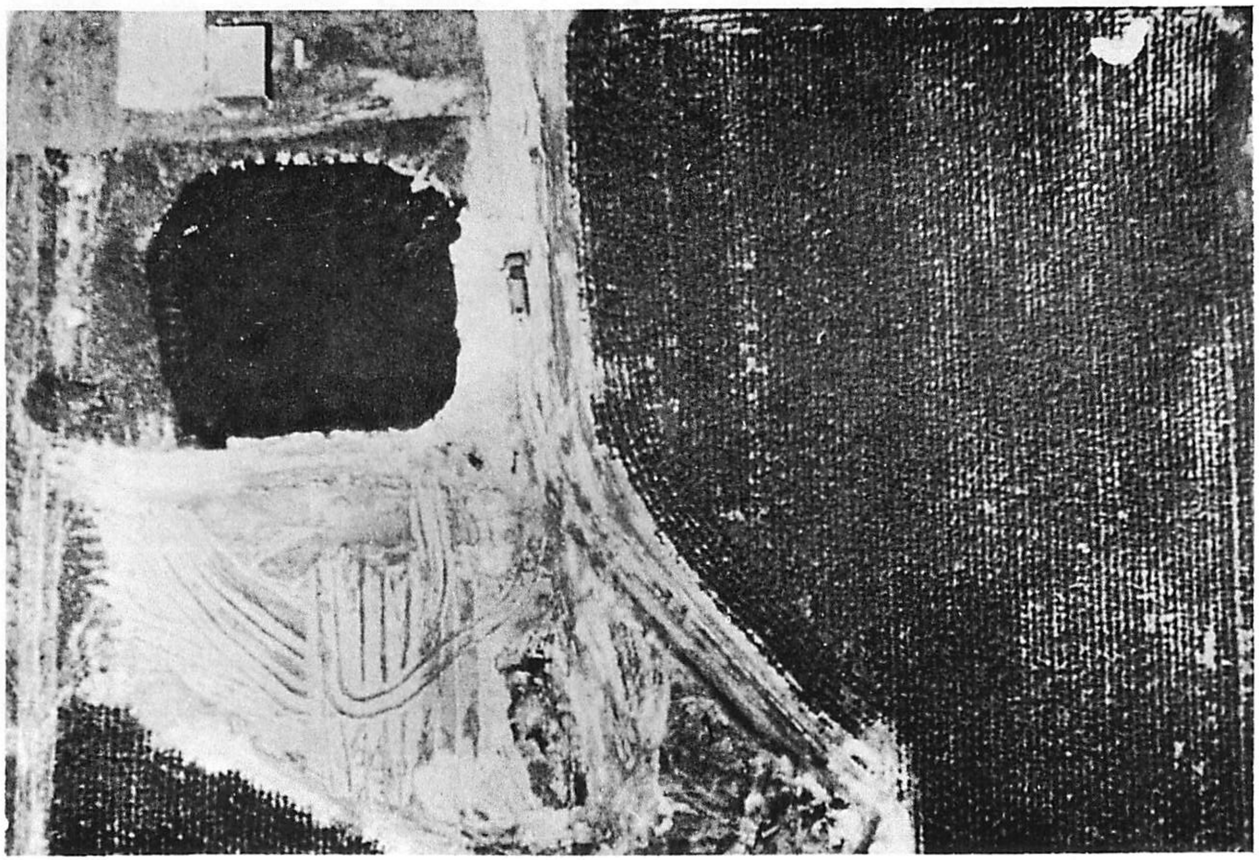


Plate 3.--Effingham-Fayette County Study Site

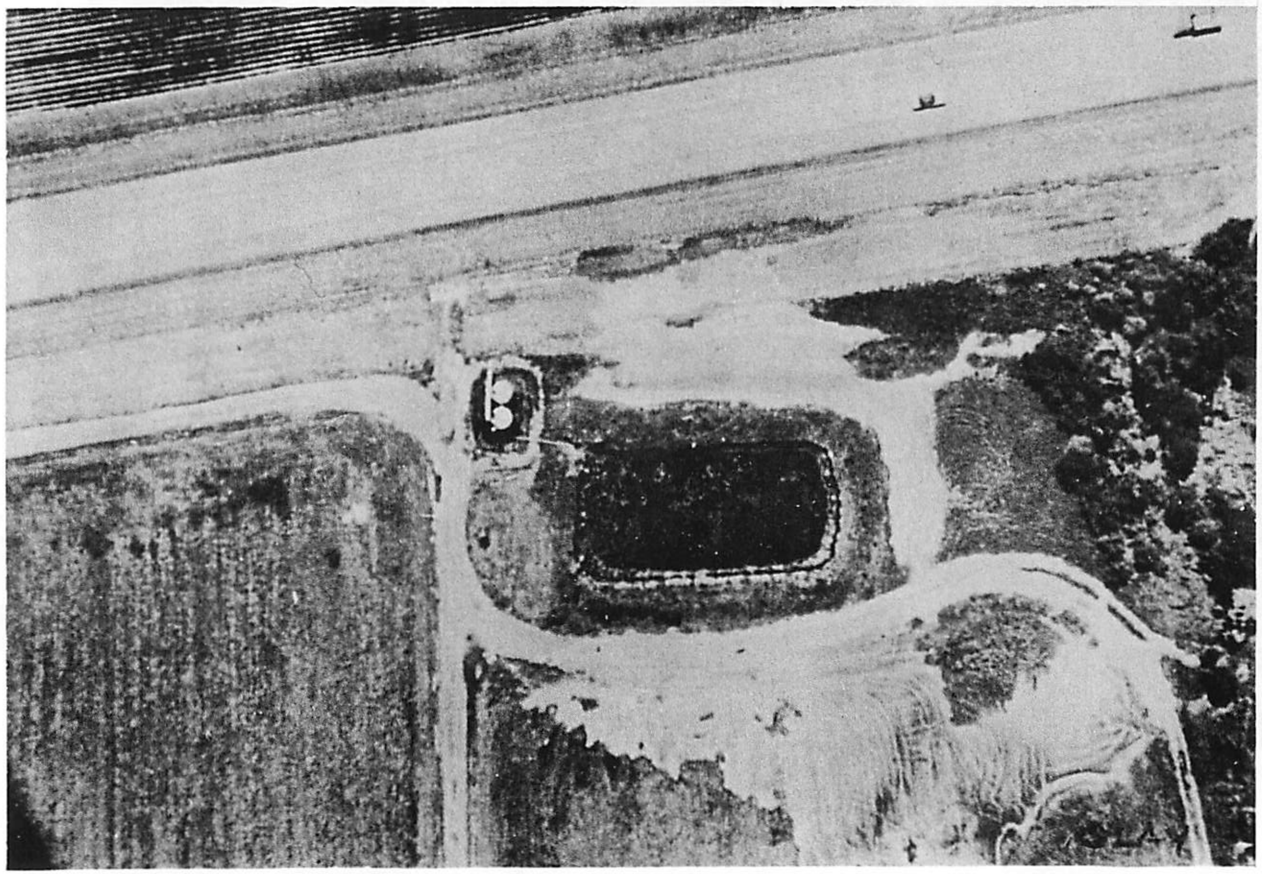


Plate 4.--Clay County Study Site

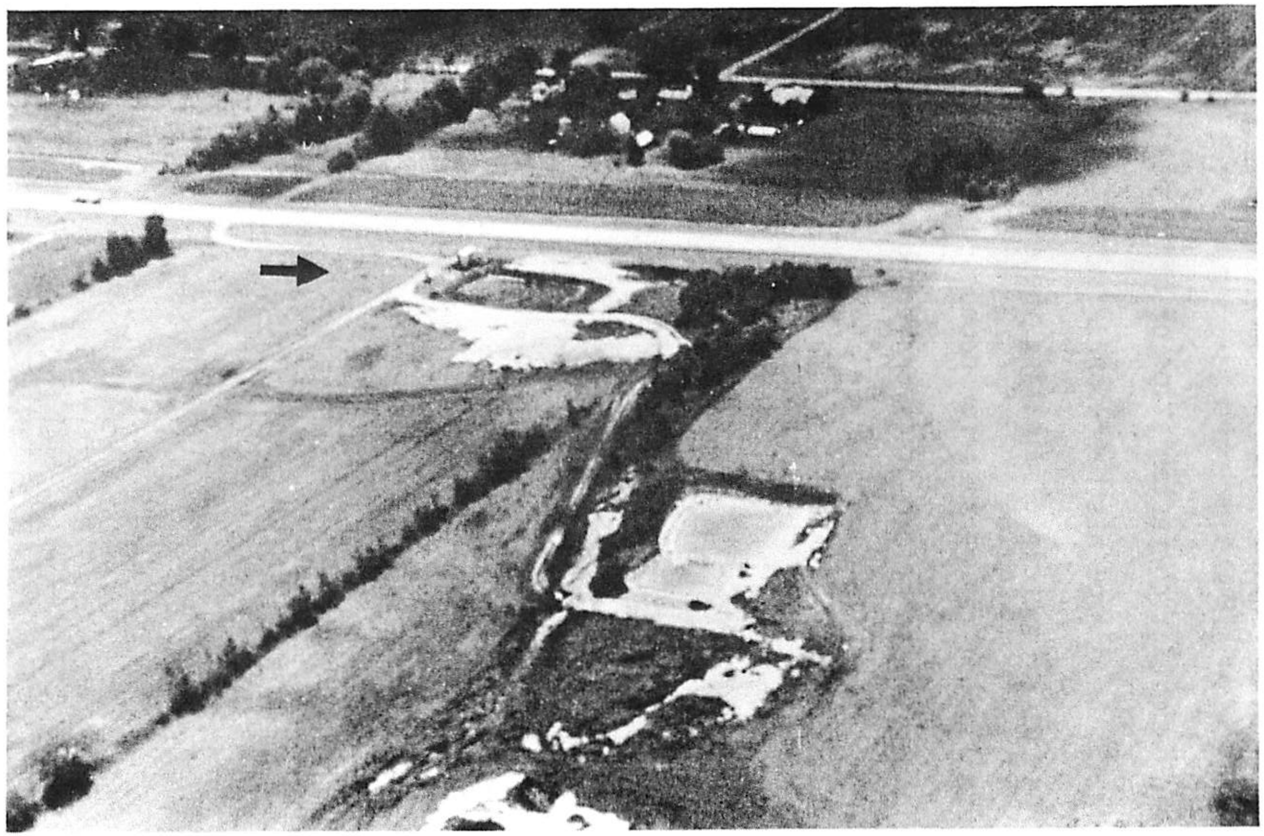


Plate 5.--Clay County Study Site (indicated by arrow)

However, even though these cases have occurred in close proximity to active oil field brine disposal operations, lack of acceptable legal evidence has left land owners without means to secure compensation for damages incurred.

One of the important characteristics of brine pollution often overlooked until the damage has been done, is that the pollution cannot be readily reversed by merely eliminating the existing source. In ground water, brine pollution may persist for decades and travel several miles from its point of origin before it is appreciably diluted.

FIELD INVESTIGATIONS

During the course of this study, considerable time was spent in the field by Agency and ISGS personnel. This section outlines the field studies and observations completed to date.

Criteria

During initial reconnaissance trips completed in May of 1978, the following criteria for selection of sites for studying environmental problems associated with oil field brine disposal, particularly unlined pits, were developed.

1. The sites should be geographically distributed across the oil producing region of the state and be in "representative" geologic environments.

2. The site should have relatively uniform geology which can be readily determined.

3. The site should have simple hydrogeology, preferably with one main water transmission zone.

4. The site should be sufficiently isolated from other sources of chloride contamination, including other brine ponds.

5. Brine disposal facilities at the site should have been in operation for a sufficient length of time (at least 10 years) so that salt water has had a chance to migrate away from the site.

6. The site and observation wells should be accessible for a period of one year, if possible, to provide a sufficient number of samples on which to base the final conclusions.

7. The layout of the site should be such that the observation wells can be located with a minimum of interference with existing property uses.

8. The site should have as few pipes and other metallic objects as possible, to preclude possible interference with resistivity measurements.

9. The land owner, tenant, and lessee of the site should be cooperative with project staff.

10. There should be no litigation or regulatory action ongoing or pending at the sites proposed for study.

Location and Study of Sites

Based on the criteria above and on the field reconnaissance work, four sites were selected for resistivity surveys, test drilling,

piezometer construction, and earth material and water sampling. The sites are located at active oil fields in Bond, Christian, Clay, and Effingham-Fayette Counties, as illustrated in Figure 5.

Lithologies encountered at the four study sites were quite similar. Three of the sites, Christian, Bond, and Effingham-Fayette Counties, possessed relatively thin deposits (1-6 ft.) of Wisconsinan loess immediately underlain by deposits of Illinoisan till, primarily of the Hagarstown member of the Glasford formation. The Hagarstown is basically comprised of four types of compact to noncompact sediments -- gravelly till, poorly sorted gravel, well sorted gravel, and sand and silt often intermixed with blocks of underlying till (Jacobs and Lineback, 1969). In most cases, the holding ponds constructed over the Hagarstown till, which covers a large portion of the oil producing area of the state (Figure 6), are excavated within 5 to 20 feet of aquifer materials consisting chiefly of sand and silt with minor amounts of gravel (Reed, 1978). Since the study sites are fairly uniform lithologically, the principal control mechanisms for chloride migration appear to be dilution from rainfall and ground water and the gradient and direction of ground water flow (Reed, 1978), as well as the static pressure differential between water table level and pit level.

Investigative Procedures

Investigative procedures at each site began with an electrical earth resistivity (EER) survey of the entire study area. With the EER method,

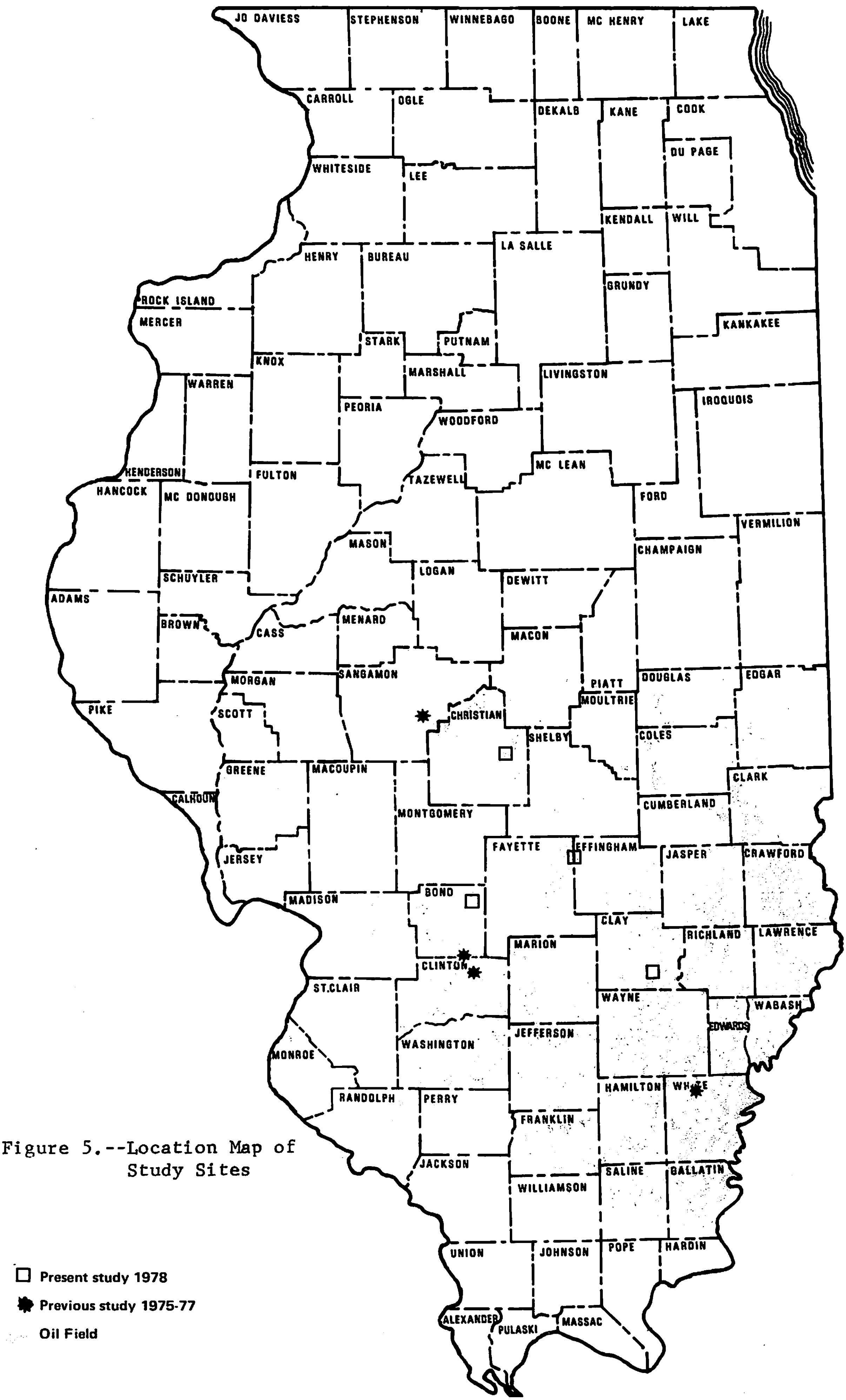


Figure 5.--Location Map of Study Sites

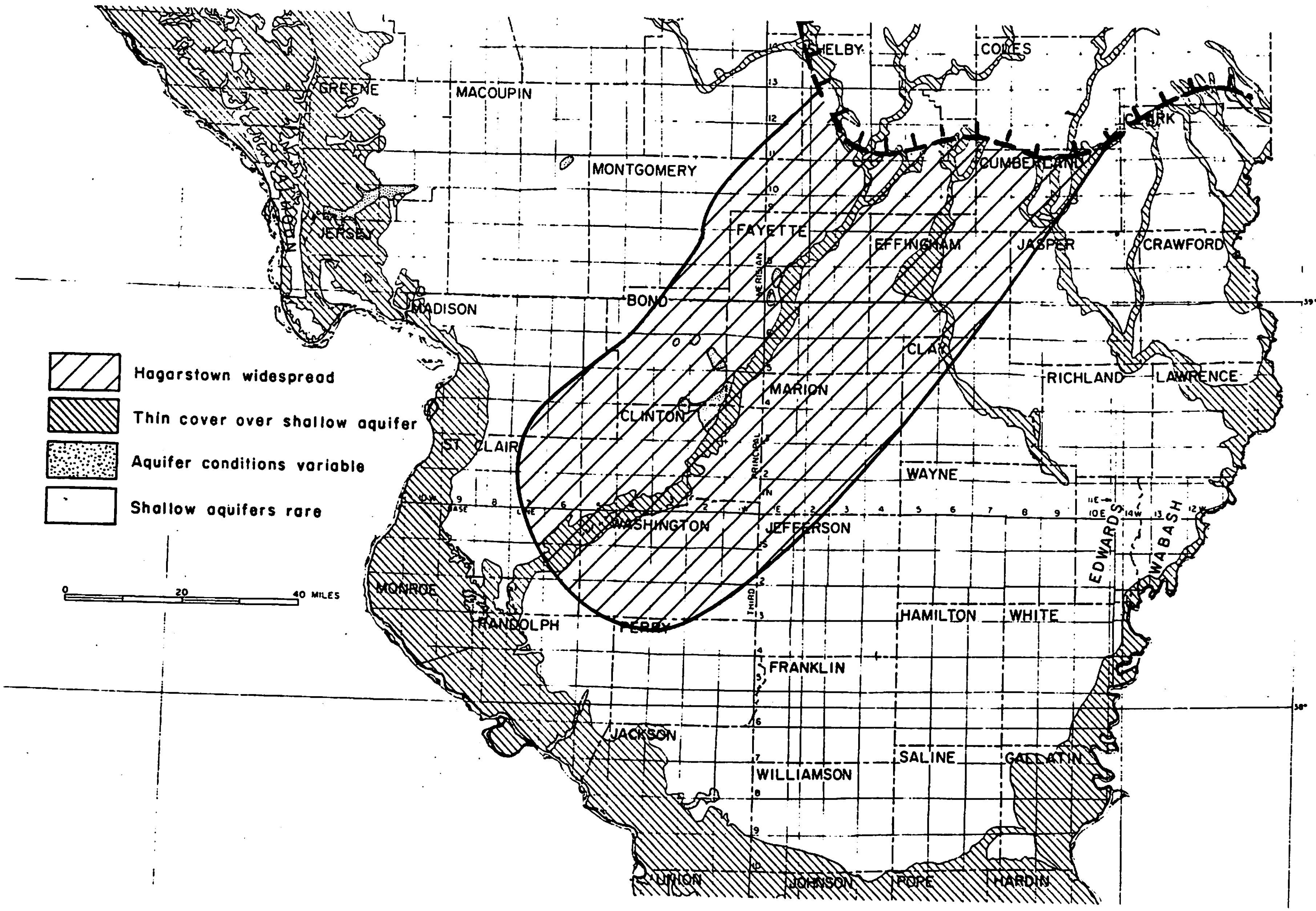


Figure 6.--Generalized Location of the Hagarstown Member of the Glasford Formation

a direct, commutated or low frequency alternating current is introduced into the ground by means of two source electrodes (metal stakes) connected to a portable power source. By mapping the resulting potential distribution created on the ground surface using two potential probes (non-polarizable electrodes), the electrical resistivity below the surface may be ascertained. By using the Wenner electrode configuration (Figure 7), in which the four electrodes are spaced equally along a straight line, the apparent resistivity can be calculated as 2π (π = 3.14) times the electrodes spacing times the recorded resistance.

This method has been used primarily in searching for water-bearing formations and in prospecting for conductive ore-bodies. EER studies have also been used to monitor the deterioration of water quality and the extent of leachate migration near landfills (Cartwright and Sherman, 1972). Success of the EER method in the applications mentioned above is due to the fact that apparent resistivity is partially controlled by the presence and quality of subsurface water. This same technique can be applied to the migration of oil field brine. The presence of highly conductive brine in the ground water is readily apparent as a depression of the normal resistivity values. The decrease in resistivity with increasing water salinity is shown in Figure 8, adopted from Guyod (1952). The greatest change in resistance occurs at the lower salinity end of the curve from 15,000 parts per million (ppm) downward. Although previous electrical earth resistivity studies conducted by the Illinois State Geological Survey have clearly related differences in subsurface resistivity measurements to the migration of oil field brine, no detailed

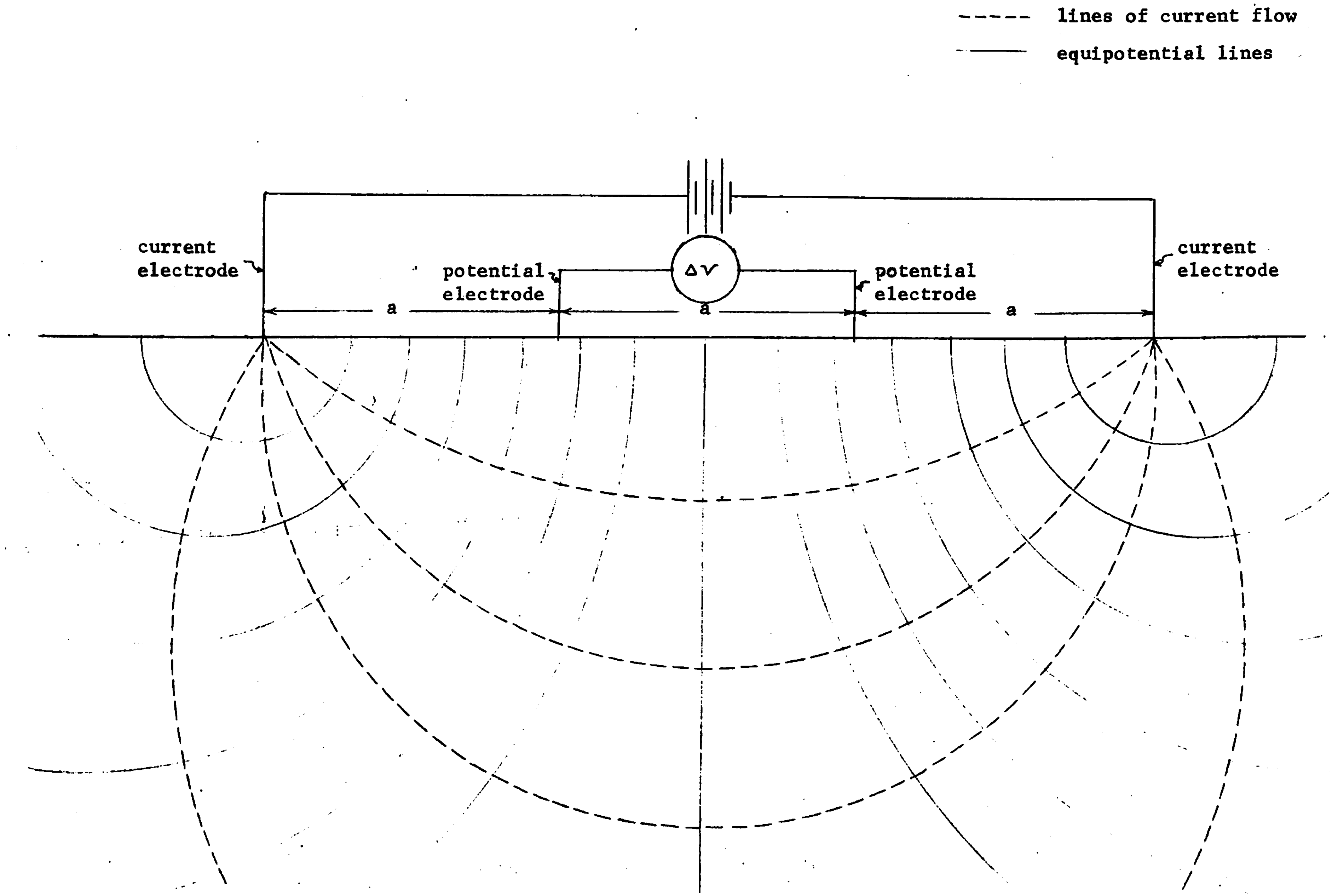


Figure 7.--Electrode Spacing for Measuring Electrical Earth Resistivity Using a Wenner Configuration.

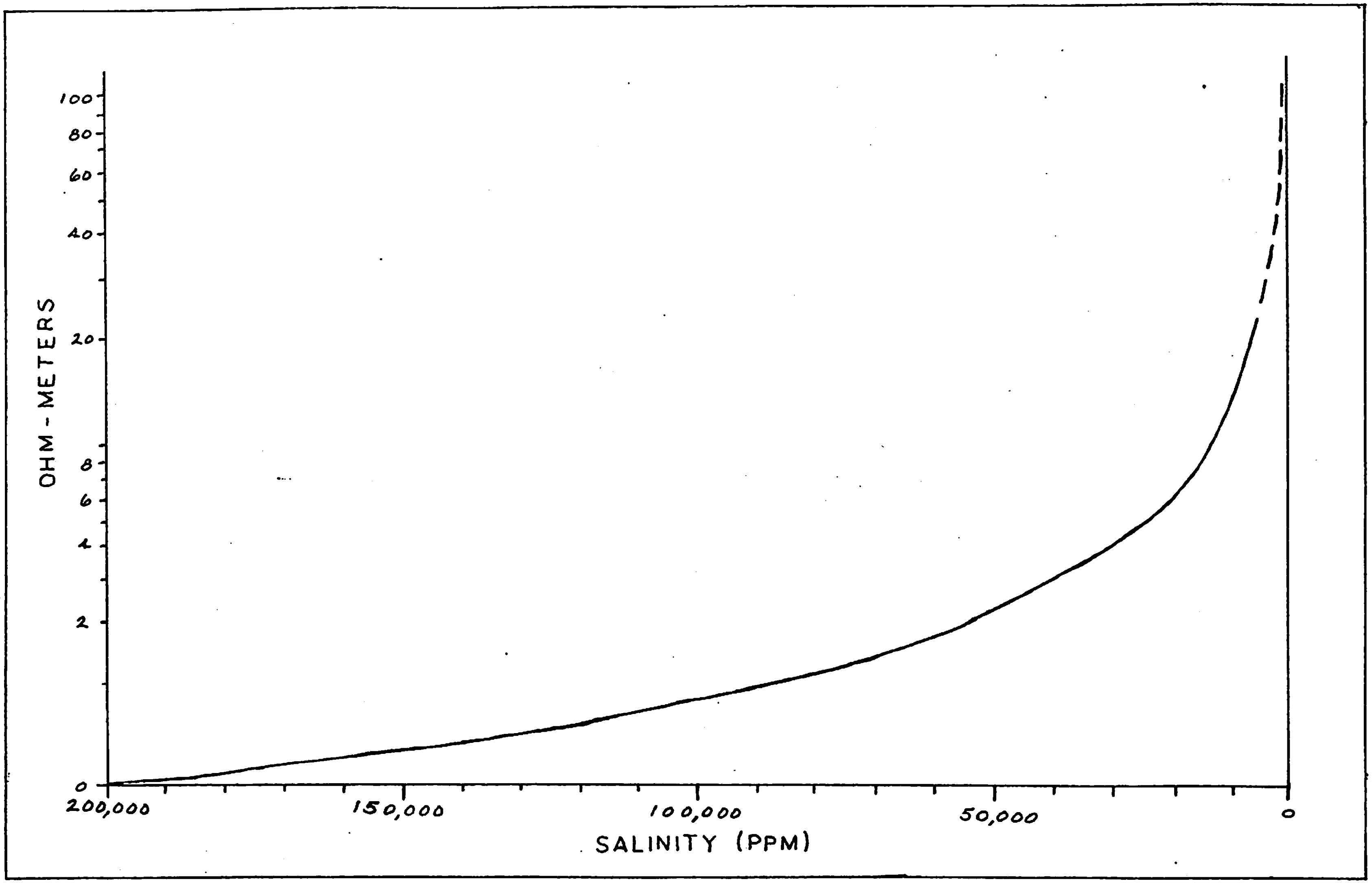


Figure 8.--Relationship of resistance and connate water salinity (from Guyod, 1952).

investigation of subsurface water quality, lithology, and surface electrical measurements had been made in the state prior to this study. Case histories of four sites previously studied in Clinton, Sangamon and White Counties are included in Appendix B. The exact locations of these sites in relationship to the current study sites are illustrated in Figure 5.

Apparent resistivity values obtained from the EER surveys were plotted and contoured for various electrode spacings. This spatial variation provides control over the depth of observation. In general, an apparent resistivity value obtained from an electrode spacing of X feet can be thought of as the apparent resistivity of the subsurface materials to a depth of X feet. However, the actual apparent resistivities of materials beneath a highly conductive layer may be masked. A comparison of surface resistivities and resistivity measurements made on drill core samples indicates this is clearly the case at the four study sites. At these sites, surface resistivity surveys suggest the presence of enlarged areas of reduced resistivity in a compact gracial till below a depth of approximately 20 feet. Low resistivities in this zone was not expected due to the impermeable nature of the material, and was discounted, after looking at core resistivities, as being caused by a masking effect of the overlying contaminated aquifer material. Contour maps for each site of the apparent resistivities obtained from electrode spacings of 5, 10, 15, and 20 feet are included in Appendices C through F.

The next step in the investigation was to locate and emplace a piezometer network. This was done by using the EER contour maps. Piezometers at each site were located so as to provide a spatial as well as an electrical resistance dispersion across the study areas.

Once located, the bore holes were augered with a portable drill rig provided by the ISGS, and split spoon samples of the earth materials were taken generally every five feet. To provide additional information on the permeability of the material and the degree of contamination of the interstitial fluids, both the number of blows required to obtain the sample and its apparent resistivity were recorded. After penetrating to an impermeable zone, usually a cobbly till, a gamma ray probe was lowered through the augers to verify the position of water-bearing earth materials. After making this determination, a plastic casing slotted opposite the most permeable zone was lowered into the bore hole. Upon retraction of the augers, the bore hole was gravel-packed, bentonite sealed and back-filled.

The measurement of static water levels and water sampling began after emplacement of the 23 piezometers at the four sites. Initially two sets of water samples were taken at semimonthly intervals to provide the data for this report. Sampling is now scheduled to continue at monthly intervals through July 1, 1979. From the laboratory analyses, average concentrations of the major constituents of water samples from each piezometer and study pit are reported in Table III.

Table III. Average Concentrations of the Major Chemical Constituents From Each Piezometer and Pit.

	Chloride ppm	Sodium ppm	Calcium ppm	Sulfate ppm	Potassium ppm	Magnesium ppm
R-Pit	14,500	11,000	370	103	25	310
R-1A	76.5	200	150	104	3.0	57
R-3B	19,750	1,250	1,000	91	7.4	585
R-16	3,900	1,900	645	65	6.6	280
R-26	95	190	50	1.5	.9	20
R-28A	22,000	14,500	800	97	11.7	505
R-32	75	100	133	53	1.2	45
R-43	27	78	303	29	.6	134
R-US	290	170	50	43	7.0	17
R-DS	14,500	10,000	510	82	8.8	310
M-PIT	10,812	7,200	540	121	22	212
M-1B	30,500	15,000	3,500	355	45	760
M-22	83	40	50	56	.6	42
M-31	2,650	1,850	265	72	2.2	105
M-33	335	372	145	73	1.2	46
M-35	35	43	82	63	1.8	37
H-PIT	24,000	16,000	1,400	725	52	470
H-3	10,000	350	550	67	2.3	250
H-11	2,850	925	1,320	29	4.5	605
H-21	20	53	93	27	1.0	38
G5A	1,400	895	525	32	4.3	230
G19A	188	162	186	54	2.6	71
G25A	126	230	94	29	13.3	45
G32	26,250	14,250	2,550	60	3.0	1,200
G32A	4,850	1,950	1,550	13	12.0	830

By applying a least squares line fit to the chloride concentration and apparent resistivity data plotted on coordinate semi-log graph paper, correlation coefficients (r) of -.76 (Figure 9) for filtered samples and -.72 (Figure 10) for unfiltered samples were obtained (Reed, 1978). This result is in general agreement with Cartwright and Sherman (1972), and signifies that EER surveys can provide a reliable, convenient technique

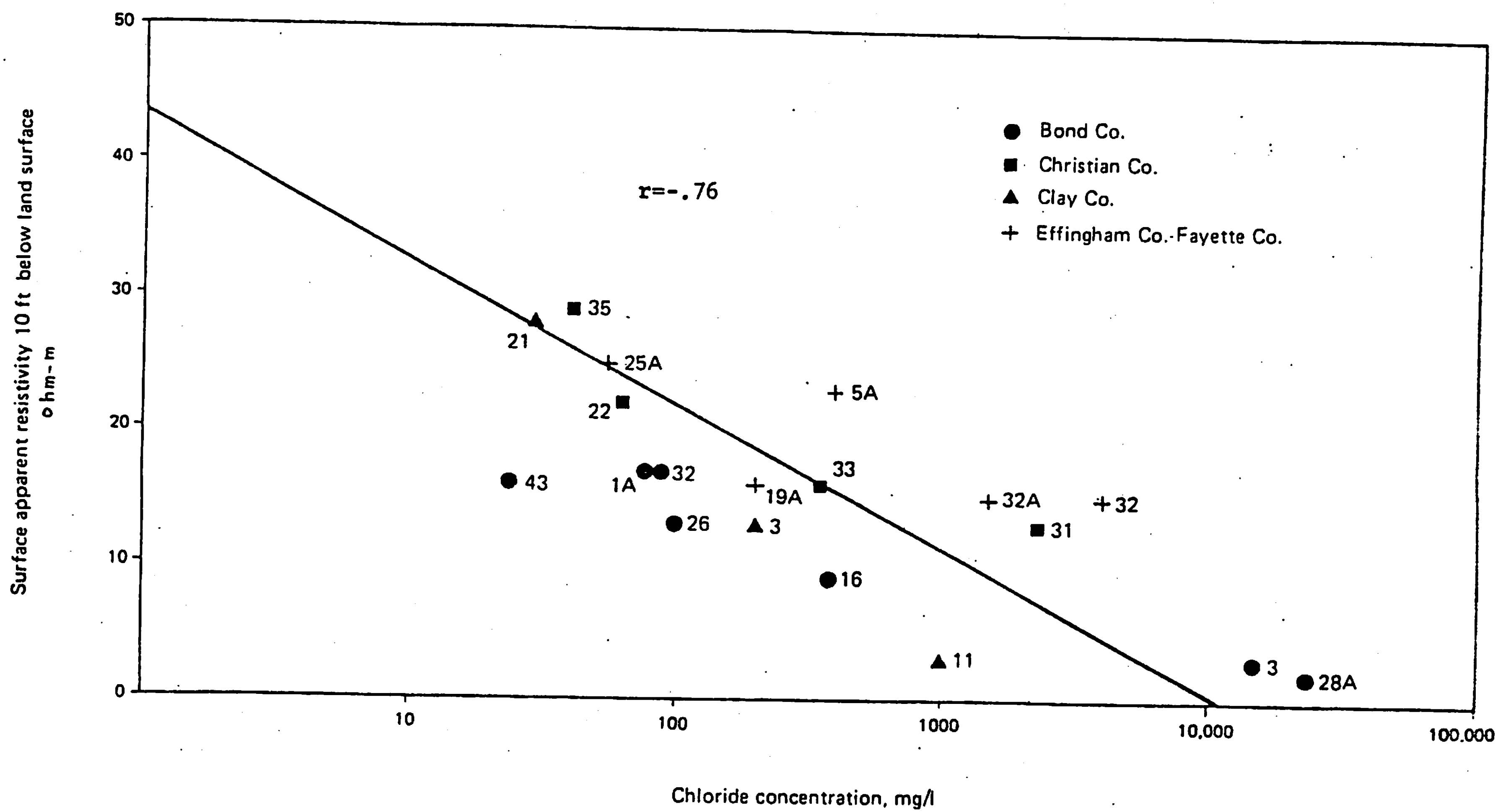


Figure 9.--Relationship of apparent resistivity and filtered chloride concentration (from Reed, 1978).

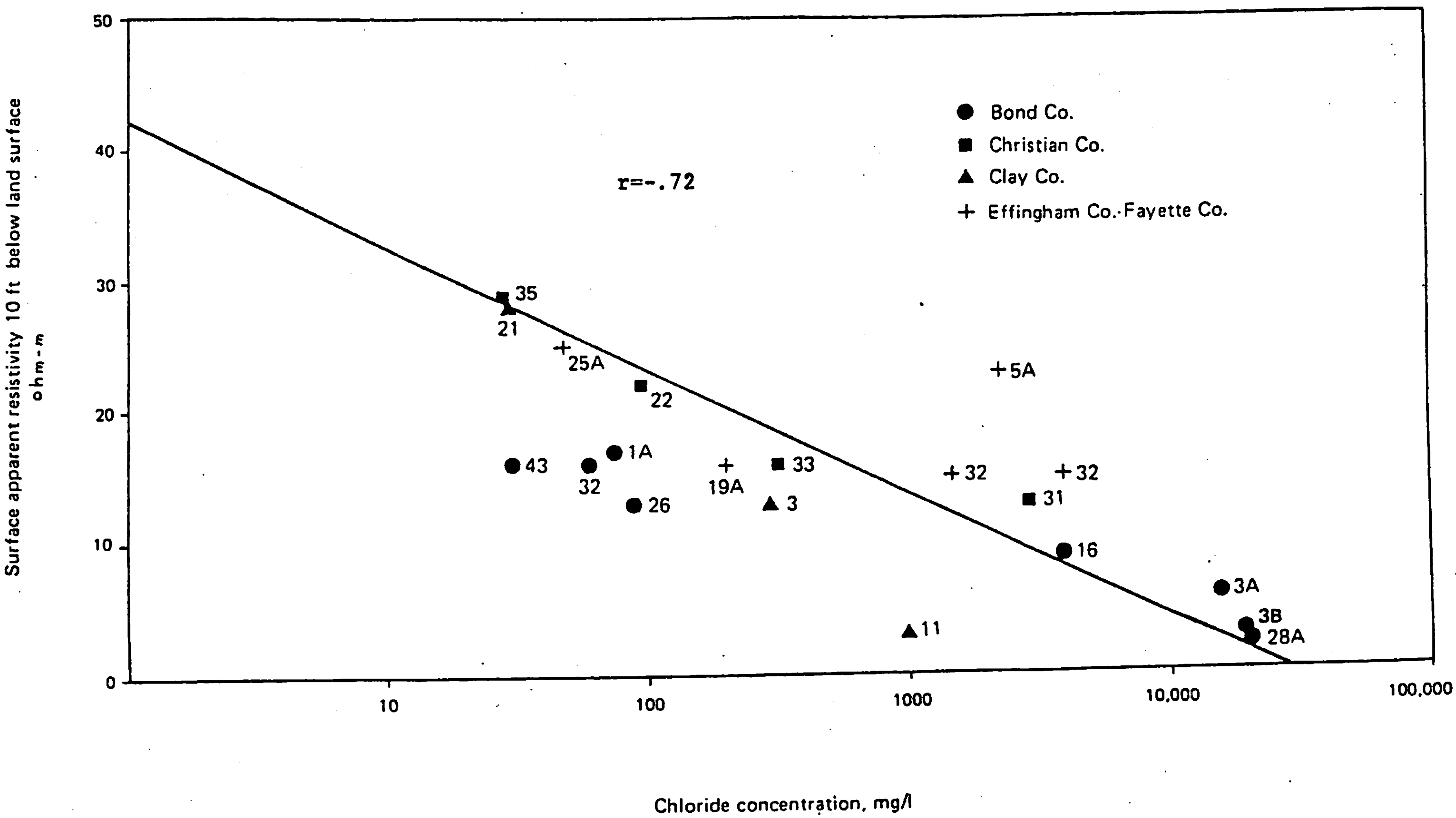


Figure 10 -- Relationship of apparent resistivity and unfiltered chloride concentrations (from Reed, 1978).

for determining the extent of subsurface oil field brine migration. Approximate chloride concentrations can also be estimated from the graphed relationship (Figures 9 and 10), given EER readings at other locations. However, since the sites in this study were confined to areas covered by the Hagarstown or similar till, additional research should be completed before making estimates of chloride concentrations in dissimilar lithologies. It is expected that further refinement of this relationship will allow chloride concentrations to be approximated with an even greater degree of accuracy and confidence in all lithologies across the state.

Field Conditions

Following is an assessment of the field conditions observed by project staff during the course of the study and a description of the three major sources of brine pollution in Illinois oil fields.

Evaporation/Seepage Pits

Evaporation pits were introduced in Illinois from the southwestern oil producing states, and rely solely or in part on evaporation for the removal of water vapor. These pits are used as ultimate disposal facilities or storage facilities pending underground injection. However, the relatively humid climate of Illinois allows little or no net evaporation throughout the year. Evaporation rates for fresh water

illustrated in Figure 11 would be significantly lower for brines due to the presence of dissolved solids and oil film (Reid et al., 1974). This suggests that evaporation pits in Illinois are capable of disposing of only small volumes of brine and are totally inadequate to handle the brine disposal requirements of a producing well.

The Department of Mines and Minerals is currently in the process of phasing out the old unlined evaporation pits. Also, new evaporation pits are currently required to be lined with impervious material (for example, plastic, concrete or fiberglass) to guard against subsurface seepage of brine, whereas clay was prescribed as the lining material prior to 1973. The fact that these liners are not indestructable and do have a limited life expectancy indicates that, although the possibility of seepage may be reduced by the use of liners it is by no means eliminated.

During the initial field investigations, it was noted that the fluid levels in at least 80 percent of the estimated 200 pits inspected were being maintained above surrounding ground level. Pits displaying breached walls were also noted. In a few instances, even though the pit was perilously close to overflowing or was in fact flowing over its banks, brine input continued at a substantial rate, i.e., 5-15 gallons per minute (Plate 6).

Other brine related problems noted in the field included remnant scars from pits which had drained into nearby streams or across open land rendering it void of vegetation (Plates 7 and 8). A few of the pits exhibit darkened halos around their peripheries indicating seepage from within. These improperly constructed or maintained pits allow brines to

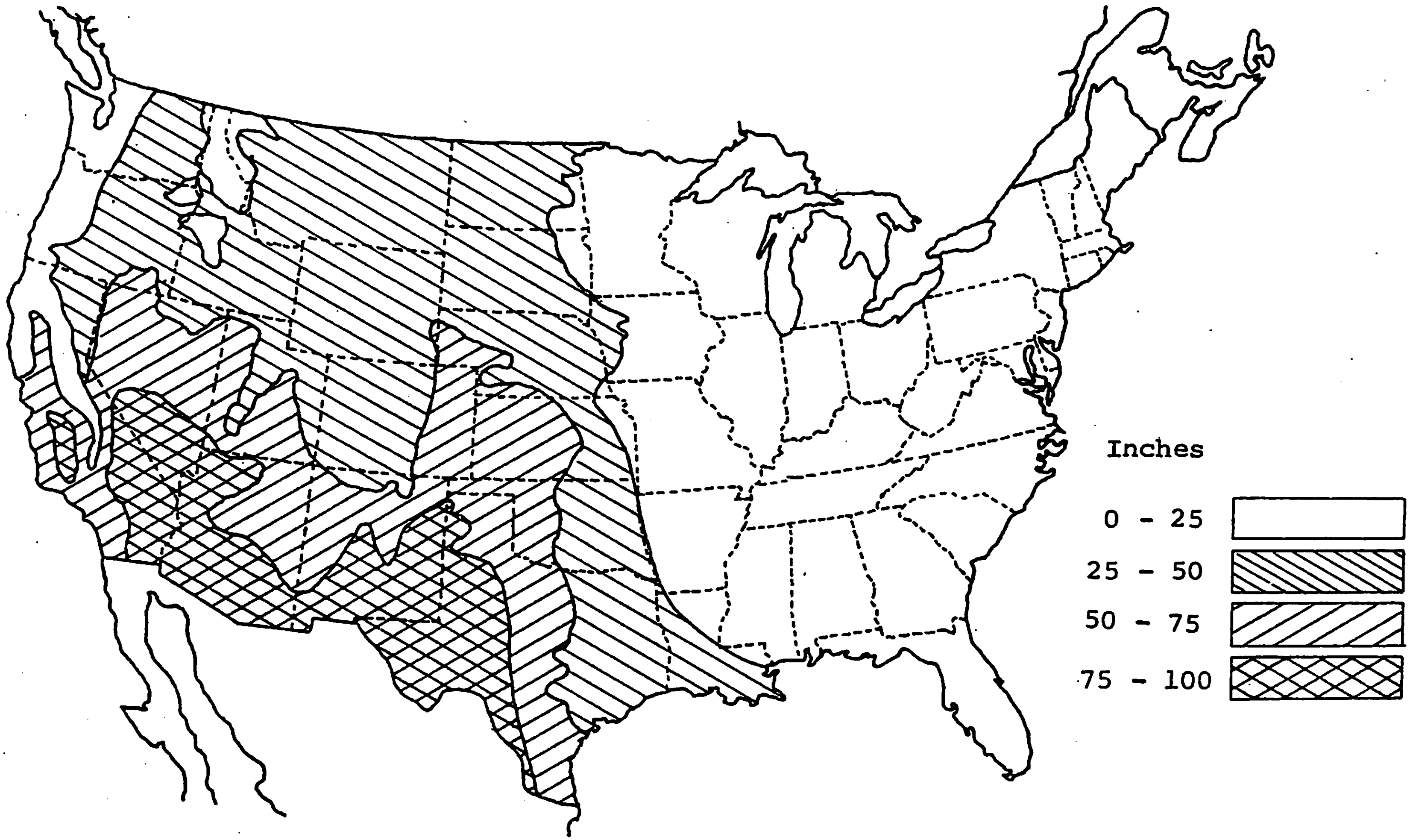


Figure11.--Map of Annual Net Evaporation in Inches (from Reed, 1978).
(pan evaporation minus precipitation)

Plate 6.--Brine Pit Overflow

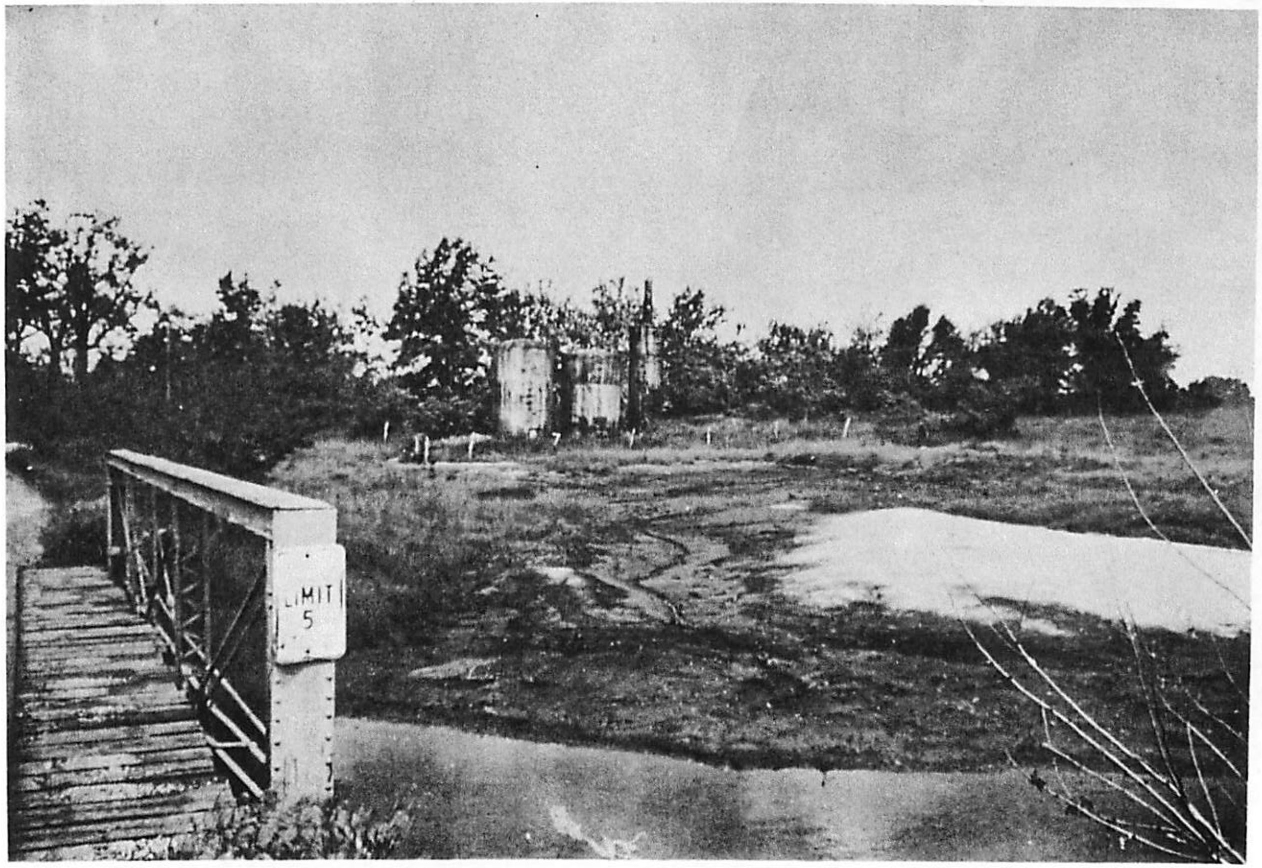


Plate 7.--Stream Pollution from Brine Runoff

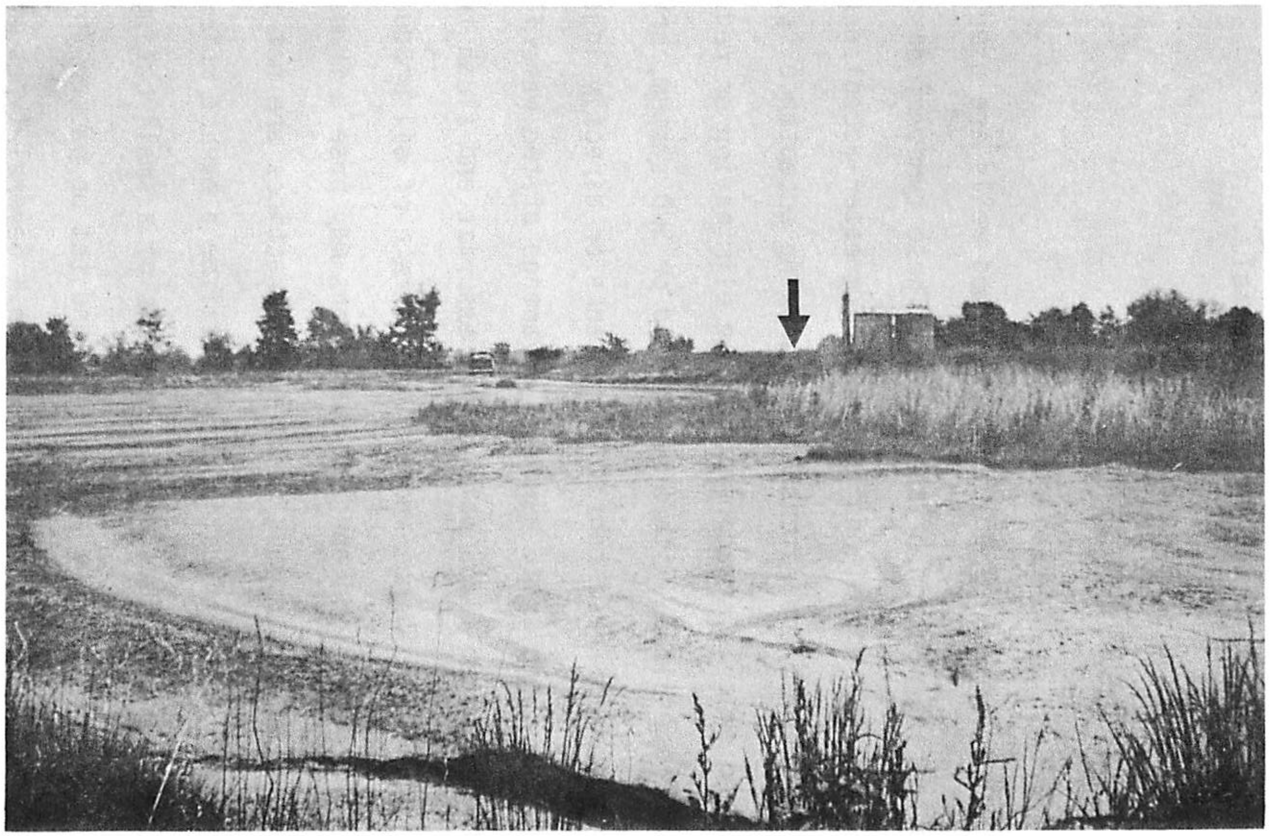


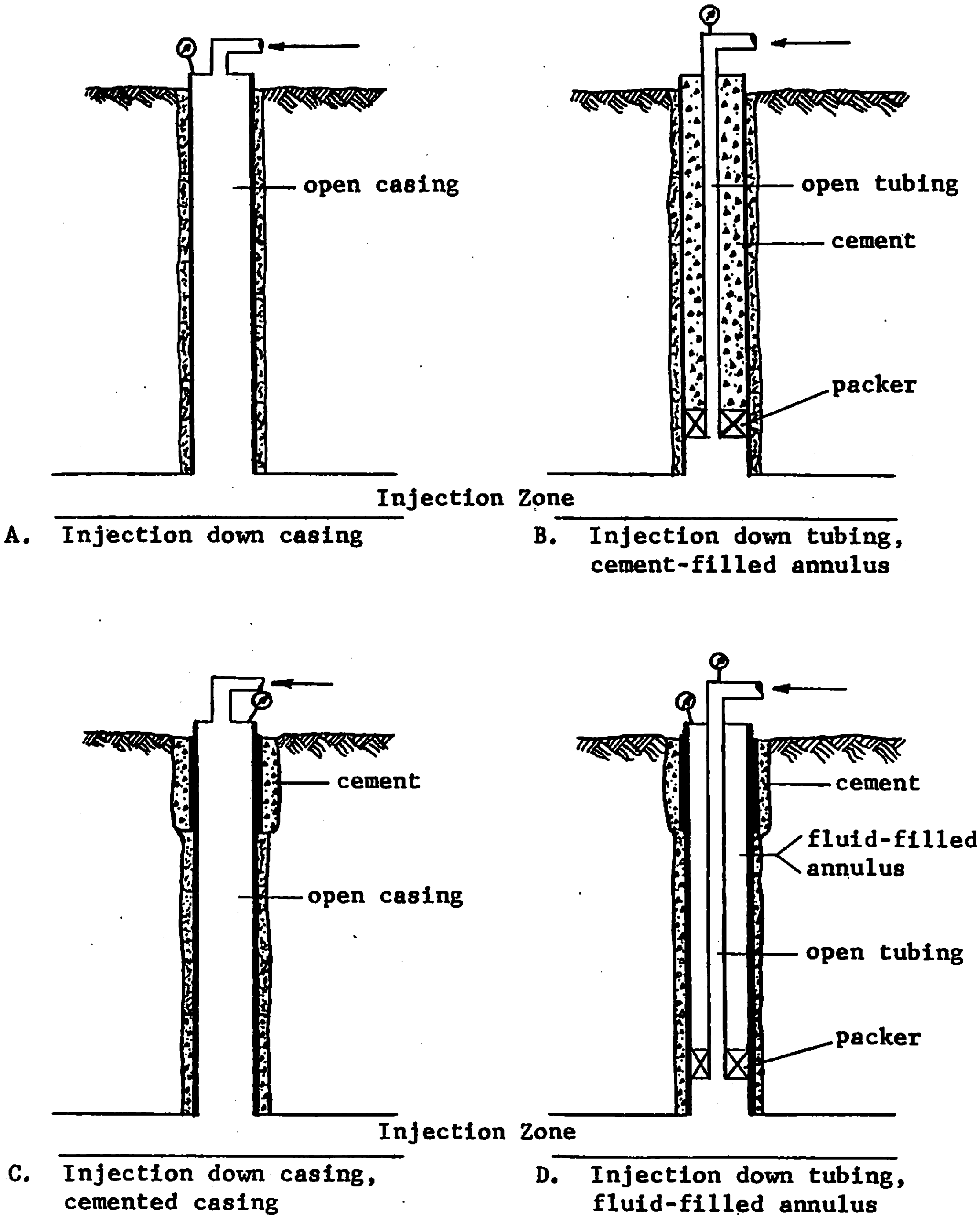
Plate 8.--Vegetation Kill from Brine Runoff
(arrow indicates location of pit)

seep into underlying soils and eventually migrate into ground water reservoirs. Once absorbed into the ground water system, the brines (particularly chlorides) can travel several miles due to their resistance against absorption into the aquifer material.

Injection Operations

Salt water disposal (SWD) and waterflood wells are used throughout the oil producing portion of the state. These types of disposal and secondary recovery operations are gaining greater acceptance from both land owners and well operators. This growing acceptance is greatly due, from the land owner's standpoint, to the elimination or reduction in the need for surface pits. With a waterflood or SWD system, brines can be stored in corrosion-resistant holding tanks or directly injected from the brine/oil separating unit. Another advantage of the waterflood operation is that the injected fluid acts to repressurize and flush through the producing formation, hence increasing the rate of oil production. However, both waterflood and SWD operations may pose a threat to ground water supplies if meticulous maintenance practices are not followed.

Many of the newer injection wells utilize a device referred to as a "tubing and packer." This device consists of a small casing or tubing which is inserted into the main casing and set or packed in place immediately above the injection formation. Several types of injection installations are illustrated in Figure 12. In addition to providing the advantage of allowing replacement of the tubing in case of failure,



A. Injection down casing

B. Injection down tubing, cement-filled annulus

C. Injection down casing, cemented casing

D. Injection down tubing, fluid-filled annulus

Figure 12.--Tubing and Packer Injection Installations

injection through tubing also provides added protection to resources outside the borehole (Warner, 1977). Although all of the tubing and packer installations provide this protection initially, continued use over long periods of time may result in corrosion and eventual casing failure which can contaminate surrounding ground water. Only an injection system which allows annulus pressure monitoring, such as one with a fluid-filled annulus (Figure 12-D) provides the capability of detecting such a failure by indicating change in annulus fluid pressure. With this type of system, continued weekly monitoring of the annulus fluid pressure would reveal a failed system before a substantial volume of ground water could be contaminated.

Many of the disposal wells presently in use may be inadequately designed or constructed to facilitate the safe injection of saline waters. In the past, abandoned production wells, subject to pressure check, could be converted to SWD or waterflood wells without installing tubing and packers. Often the casing in an old well has deteriorated from years of exposure to corrosive formation fluids. Although such a casing may withstand an initial pressure check, its subsequent life expectancy could be substantially shortened. When failure does occur, chloride solutions can be expelled at injection pressure into the adjacent strata, as illustrated in Figure 13. Due to the relatively slow rate of migration and to the fact that salt water injection wells are not frequently monitored for unexpected injection pressure changes, large volumes of ground water can be polluted before casing breaks are discovered.

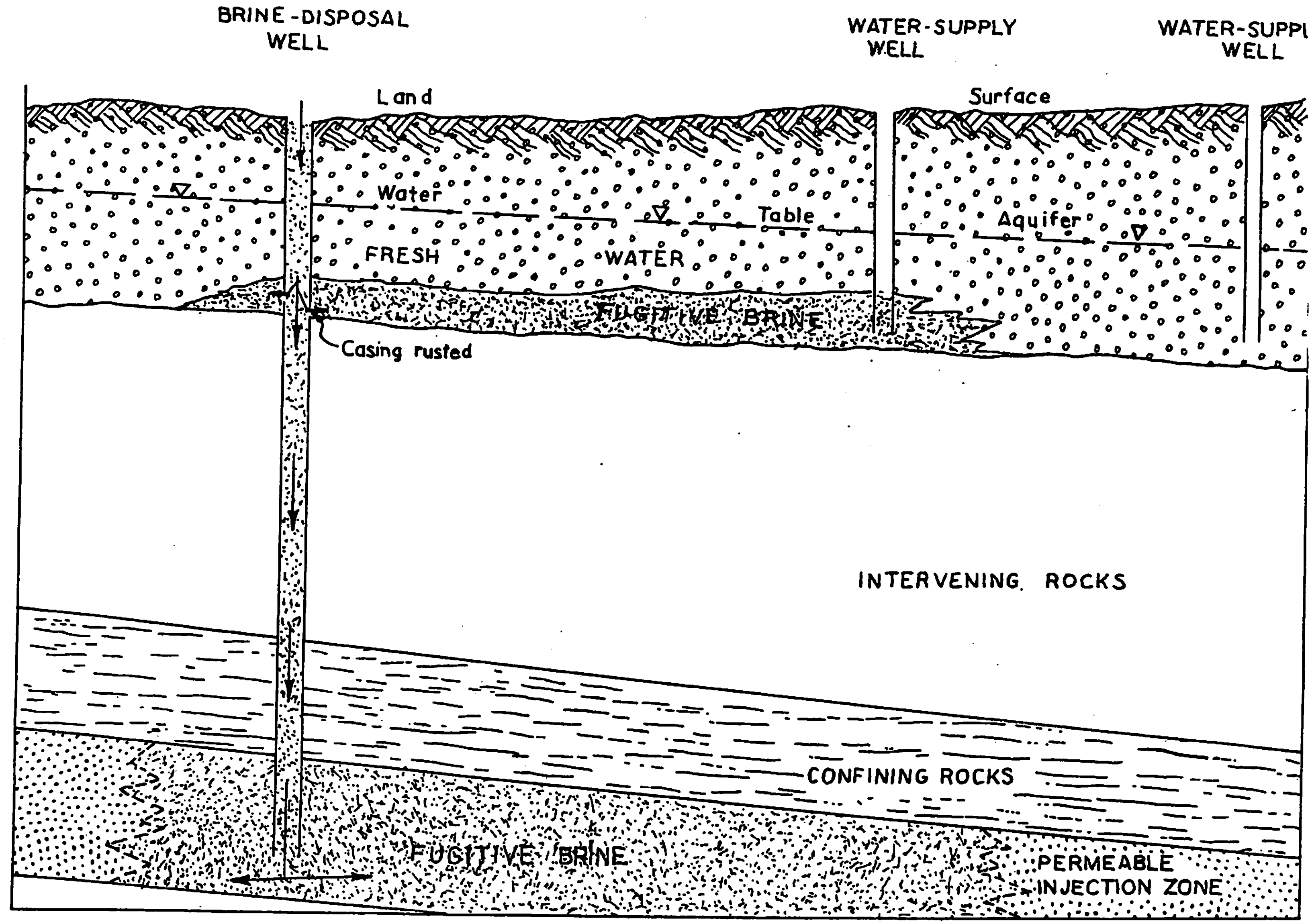


Figure 13.--Pollution of a Fresh Water Aquifer Through a Failed Injection Casing

Abandoned Wells

In old production areas, abandoned wells may pose a serious threat to ground water quality. Unplugged or improperly plugged wells provide possible vertical communication between saline and fresh water aquifers. An increase in formation pressure due to secondary recovery operations can supply the hydraulic pressure required to transfer the saline fluids from depth to an elevation adjacent to a fresh water aquifer, via an abandoned casing (Figure 14). Once this situation is established, the corrosion process and the failure of the casing are hastened.

During the relatively limited field reconnaissance, a few unplugged, uncapped and improperly plugged wells were noted. In addition to these, the records of the Illinois Department of Mines and Minerals indicate that there are thousands of plugged wells within the state. Many of these wells were plugged prior to the 1940's before plugging records and specifications were developed, and may not have retained the integrity necessary to restrict vertical migration of highly saline waters. Ultimately, the migration of saline waters through these casings could lead to the degradation of otherwise potable ground water resources.

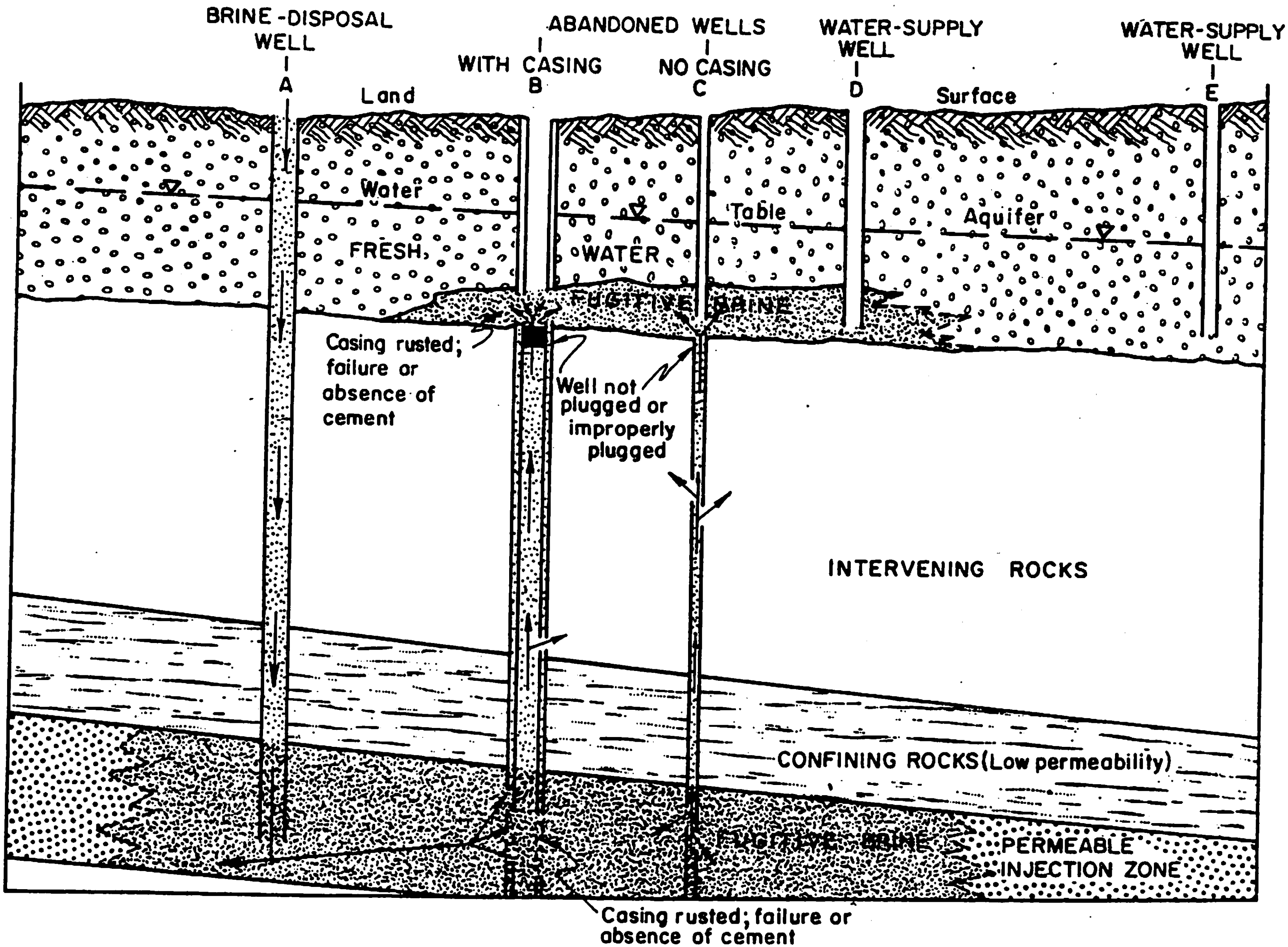


Figure 14.--Pollution of a Fresh Water Aquifer Through Abandoned Wells (from Newport, 1977)

PRELIMINARY FINDINGS

1. During field investigations, ground water contamination at four study sites was found to be more extensive than the damage visible at the surface. This indicated substantial seepage from beneath the four brine holding ponds.

2. Analysis of stream samples obtained at a study site in Bond County exhibited high chloride concentrations. This was most likely due to highly saline waters seeping from beneath a nearby brine holding pond, into the aquifer which serves as a recharge source for the stream. Chloride concentrations recorded 200 feet downstream from the pond (i.e, 14,500 ppm, a value far greater than the maximum contaminant level of 500 ppm set by the Illinois Pollution Control Board) were equivalent to those recorded within the pond. This situation indicates the impact of improperly handled brines on water quality.

3. A correlation coefficient (r) of -.76 was found between ground water quality data (chloride concentrations) and surface electrical earth resistivity measurements obtained at each site. This degree of correlation suggests that EER surveys can be used as a valid method in studying subsurface migration of oil field brines.

4. From field observations, it was noted that a larger incidence of brine related pollution appeared to emanate from older facilities. This is probably due in part to advanced stages of corrosion of well casings, and increased brine/oil ratios.

5. Taking into account the damaging effects of brine pollution and the volume of salt water disposed of daily, it is evident that strict enforcement of existing regulatory guidelines for the disposal of oil field brines is essential for the protection of currently utilized and potential ground water sources.

PRELIMINARY RECOMMENDATIONS

1. The Department of Mines and Minerals and the Illinois EPA should investigate a means to accelerate the program, initiated in 1973, for eliminating unlined brine pits. A target date with annual goals should be established for phasing out the estimated 4,000 remaining brine pits in Illinois.

2. All injection wells should be constructed with an annulus that can be pressure-monitored. The pressure on such an annulus should be monitored weekly to insure early detection of any failures in the system. This construction and recording requirement should be considered by the Illinois EPA in its review of the pending federal underground injection control program developed under provisions of the Safe Drinking Water Act.

3. Illinois EPA should continue geophysical and water quality testing to better assess the surface and subsurface impacts of brine pollution across the state. In addition to assessing the extent of pollution, investigations into feasible means of rehabilitating chloride contaminated aquifers and soils should be made through proposals for federal funding from the USEPA.

4. A detailed professional legal assessment should be made by the Illinois EPA of all current and proposed regulatory programs pertaining to the disposal of oil field brine.

GLOSSARY

Annulus: The space between the tubing casing and the long string or outside casing.

Anticlinal Belt: A series of folds in the underlying geology that are convex upward or had such an attitude at some stage of development.

Apparent Resistivity: The resistance of rock or sediment to an electrical current per unit volume as measured by a series of current and voltage electrodes on the surface of the earth. It is equivalent to the actual resistivity if the material is truly uniform.

Aquifer: A porous, permeable, water-bearing geologic body of rock or sediment, generally restricted to materials capable of yielding an appreciable amount of water.

Back-filled: The refilling of an augered hole with earth material after emplacement of the casing.

Bentonite Sealed: The sealing of the permeable reservoir from the back-fill material by covering the reservoir with a water absorbing clay material, bentonite.

Cations: An ion that bears a positive charge.

Correlation Coefficient: A dependency or association factor between two parameters. Coefficients range from -1 to 1 with the mid-point 0 indicating a total lack of correlation.

Corrositivity: The ability to deteriorate or destruct substance or material by chemical action.

Formation: A uniform body of rock; it is most often tabular and is mappable on the earth's surface or traceable in the subsurface.

Gamma Log: A graph of the natural radioactivity of rocks obtained by lowering a gamma ray probe into a bore hole.

Gamma Ray Probe: (Geiger-Mueller) A probe or counter capable of measuring the intensity of radioactivity in the surrounding rock.

Gradient: (Hydrological) Slope of the regional water table.

Gravel-Packed: Placement of gravel around the open portion of a casing to provide a permeable reservoir for inflowing waters.

Ground Water Pollution: (As defined for this report.) The elevation of chemical constituent concentrations (primarily chlorides) above those existing naturally in the regional ground water.

Hydrofracing: Process of increasing the permeability of rock near a well by pumping in water and sand under high pressure.

Hydrogeology: The study of ground water movements in the underlying geology.

Illinois Basin: The structural basin in southeast central Illinois in which the rocks dip generally toward a central point.

Interstitial: That which exists within an opening of space in a rock or soil that is not occupied by solid matter.

Leachate: A solution obtained by leaching, as in the extraction of soluble substances by the downward percolation of rain water through soil or solid waste.

Lithologies: The physical characteristics of rocks such as color, structures, mineralogic composition, and grain size.

Loess: A uniform, nonlayered deposit of silt, fine sand and/or clay.

Permeable: Having a texture that permits water to move through it.

Piezometer: A casing providing access to the static water level in an aquifer, and through which ground water samples may be extraced.

Potential Distribution: The resulting dispersion of an electrical current artifically introduced into the ground.

Reef Deposits: A mound-like or layered rock structure initially built by organisms such as corals and subsequently buried by sediment.

Till: Nonsorted, nonlayered sediment carried or deposited by a glacier.

Water Transmission Zone: A zone of material below the surface of the earth capable of transmitting water.

Waterfloods: The secondary recovery operation in which water is injected into a petroleum reservoir for the purpose of increasing oil production.

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DP:sh/sp/5367/1-37

APPENDIX A

Problem Report Form

Illinois Environmental Protection Agency

"208" CLEAN WATER MANAGEMENT PLANNING PROGRAM
OIL FIELD BRINE DISPOSAL PROBLEM REPORT

PLEASE READ

Because of reports from concerned citizens like yourself, the Illinois Environmental Protection Agency is conducting a detailed study of water pollution problems associated with oil field brine disposal in your area of the state.

The purposes of this study are to determine how existing brine disposal problems can be solved most effectively, and how we can better ensure that no additional problems are created in the future.

In order to help us, please take a minute or two and fill out the attached Problem Report. It asks only for basic information to assist us in becoming familiar with problems you may know about.

If you wish to be kept informed of the progress of this study or would like to talk with us directly, please fill in your name and address. THIS PROBLEM REPORT IS NOT AN OFFICIAL COMPLAINT OR OTHER LEGAL DOCUMENT AND CANNOT BE USED IN ENFORCEMENT PROCEEDINGS.

The ILLINOIS DEPARTMENT OF MINES AND MINERALS, Oil and Gas Division, is responsible for investigating public complaints concerning oil field brine disposal. If you wish to file an official complaint, you should contact: Mr. George Lane; Oil and Gas Division, Illinois Department of Mines and Minerals, 704 Stratton State Office Building, 400 South Spring Street, Springfield, Illinois 62706, Phone (217) 782-7756.

Please return the completed form to the person named below. Feel free to contact him if you have any questions about this study:

Donald R. Osby
Illinois Environmental Protection Agency
Planning and Standards Section
Division of Water Pollution Control
2200 Churchill Road
Springfield, Illinois 62706
Phone (217)782-3362

You may tear off this sheet and keep if for reference.
Thank you for your participation.

DO:bl/2111/8

2200 Churchill Road, Springfield, Illinois 62706

"208" CLEAN WATER MANAGEMENT PLANNING PROGRAM

OIL FIELD BRINE DISPOSAL PROBLEM REPORT

Date: Meeting Place (Town):

I. GENERAL INFORMATION

Citizen Name and Address:

Well Operator or Lessee Name and Address, if known:

This individual is: ____ well operator ____ lessee (check one).

Well Location:

County:____________________ Township____________________ (if known)

Range ____________________ (if known)

Section ____________________ (if known)

(If possible, locate well on the county map.)

II. BRINE PROBLEM INFORMATION

Well Operation:

Is the well presently producing oil? ___Yes ___No

If not, how long has the well been out of production?

Disposal System:

What type of brine disposal system if being used?

____Evaporation ponds ___Injection wells ___Other ______

(specify)____

Pollution Affects:

What are the affects of the brine pollution?

_____ Damage to vegetation _____ Contamination of water supply

_____ Other (specify)____

____

Problem:

What is the nature of the problem:

______ Leaking pond _____ Broken pipe ______ Faulty firewall

____ Other (specify)____

When was the problem first noted?

____

Has anyone been notified of the problem? _____Yes _____No

If so, whom and when?____

____

Have any actions been taken? _____Yes _____No

If so, by whom and what actions? _____________________________________

____

APPENDIX B

Selected Samples of Previously Completed E.E.R. Studies

ILLINOIS STATE GEOLOGICAL SURVEY
NATURAL RESOURCES BUILDING, URBANA, ILLINOIS 61801 TELEPHONE 217 344-1481
Jack A. Simon, CHIEF

September 2, 1977

A RECONNAISSANCE ELECTRICAL EARTH RESISTIVITY SURVEY AT A BRINE DISPOSAL PIT IN SECTION 31, T. 4 N., R. 2 W., BOND COUNTY, ILLINOIS

By

Keros Cartwright, Geologist and Head
Philip C. Reed, Assistant Geologist
Hydrogeology and Geophysics Section

Introduction

At the request of Mr. George R. Lane, Department of Mines and Minerals, State Office Building, Springfield, Illinois, 62706, a reconnaissance electrical earth resistivity survey was made on August 16, 1977, within and adjoining the Dwight Follett lease, Beaver Creek Field, in the NW¼ Section 31, T. 4 N., R. 2 W., Bond County. We were assisted in the fieldy by Mr. Leonard Strum from the Department of Mines and Minerals. The purpose of the study is to determine if the brine in the pit on the lease is leaking to the ground-water reservoir and, if it is leaking, to determine the distribution of the salt water wedge.

Hydrogeologic Setting

The brine pit is located in a region of gently sloping terrain of the Illinois till plain between Greenville and Carlyle, Illinois. There are a number of oil well logs from the immediate area in the Geological Survey files, including two on the Follett lease. Copies of the first page of these logs are attached. Unfortunately, the description of the surficial material is very poor and often contradictory. The logs do suggest the presence of a sandy or gravelly zone at 10 to 15 feet below land surface. This interpretation is consistent with our regional stratigraphic information.

The site is similar to two sites studied in detail about 10 miles to the south. There are four glacial tills in this region. The uppermost till is the Hagerstown, which is the sandy, gravelly till forming the prominent ridges in the region. The hills being quarried for sand and gravel just south of the brine pit consist of a thick Hagerstown sequence. On lower flat ground such as that found around the brine pit, the Hagerstown is quite thin and found at depths of 10 to 20 feet. The clayey Vandalia till underlies the Hagerstown; overlying the Hagerstown is a sequence of gleys and silts (loesses). Generally, the Hagerstown and overlying sediments have undergone several episodes of soil genesis, beginning with the formation of the Sangamon soil, continuing through two or more periods of soil genesis during the Wisconsinan and culminating with the modern soil formation. The Hagerstown beds and some sandy zones associated with the overlying loesses are relatively permeable.

A generalized observation of the hydrogeology can be made from analysis of the topography of the area near the brine pit. Our observations of the topography indicate that if any brine is entering the ground water it would flow north or north-northwest to the small, unnamed stream (a tributary to Beaver Creek) which flows across the northwest corner of Section 31. Discharge of ground water would occur along the creek and possibly in the small drainage swale which transverses, in a northeasterly direction, the property just north of the pit.

Resistivity Survey

The electrical earth resistivity survey is based on the principle that uncontaminated, compact glacial till, clay-alluvium and shale present more resistance to the passage of an electrical current than do sand and gravel, or sandstone and limestone of the bedrock. However, resistance to the passage of electricity through earth materials is a property of both the rock type and the water contained in its pores. Electrical current introduced in earth material containing water with high concentration of soluble salts will have a greatly reduced electrical resistance. This relationship has been demonstrated in numerous published papers; it has also been demonstrated that electrical earth resistivity surveying can be used to map contaminated ground water (see enclosure).

Results

During the survey of the pit area, we made 23 electrical depth sounding profiles. The accompanying map, modified from the one made by Clifford H. Simonson for Mr. Arnold R. Edwards, shows the approximate location of the resistivity soundings. Also enclosed are copies of all the depth soundings; no profile could be obtained at station no. 14 because surface conductance prevented penetration of the electrical field into the ground. In normal, uncontaminated, uniform materials the "a" spacing (taken from the geometry of the Wenner electrode configuration we used) is approximately equal to the depth of penetration of the electrical field. However, a very conductive layer (very low resistivity) such as a salt water zone, will disturbe the electrical field, reducing the depth of penetration.

We drew slice maps for all "a" spacing from 10 to 50 feet. All show the same relationship; a region of greatly depressed apparent resistivity extending northwestward from the pit to the stream. This region of depressed resistivity is shown on the accompanying map. Resistivity stations showing normal profiles are numbers 1, 10, 11, 12, 13, 17, 19 and 23. Station numbers 3, 4, 5, 6, 14, 15, 20 and 21 are strongly effected by highly conductive material. Station numbers 2, 7, 8, 9, 16, 18 and 22 are intermediate.

Two characteristics of the depth sounding profile taken in the strongly effected area are apparent. The first type, best shown at station no. 15, shows a decline in resistivity values from the initial reading at a = 10 feet. This suggests that the surface soils do not have significant accumulations of electrolites. Stations showing this characteristic, numbers 3, 4, 5, 6, 9 and 15, are all in soil with good crop vegetative cover (except number 15 which is a grassy part of the fallow field).

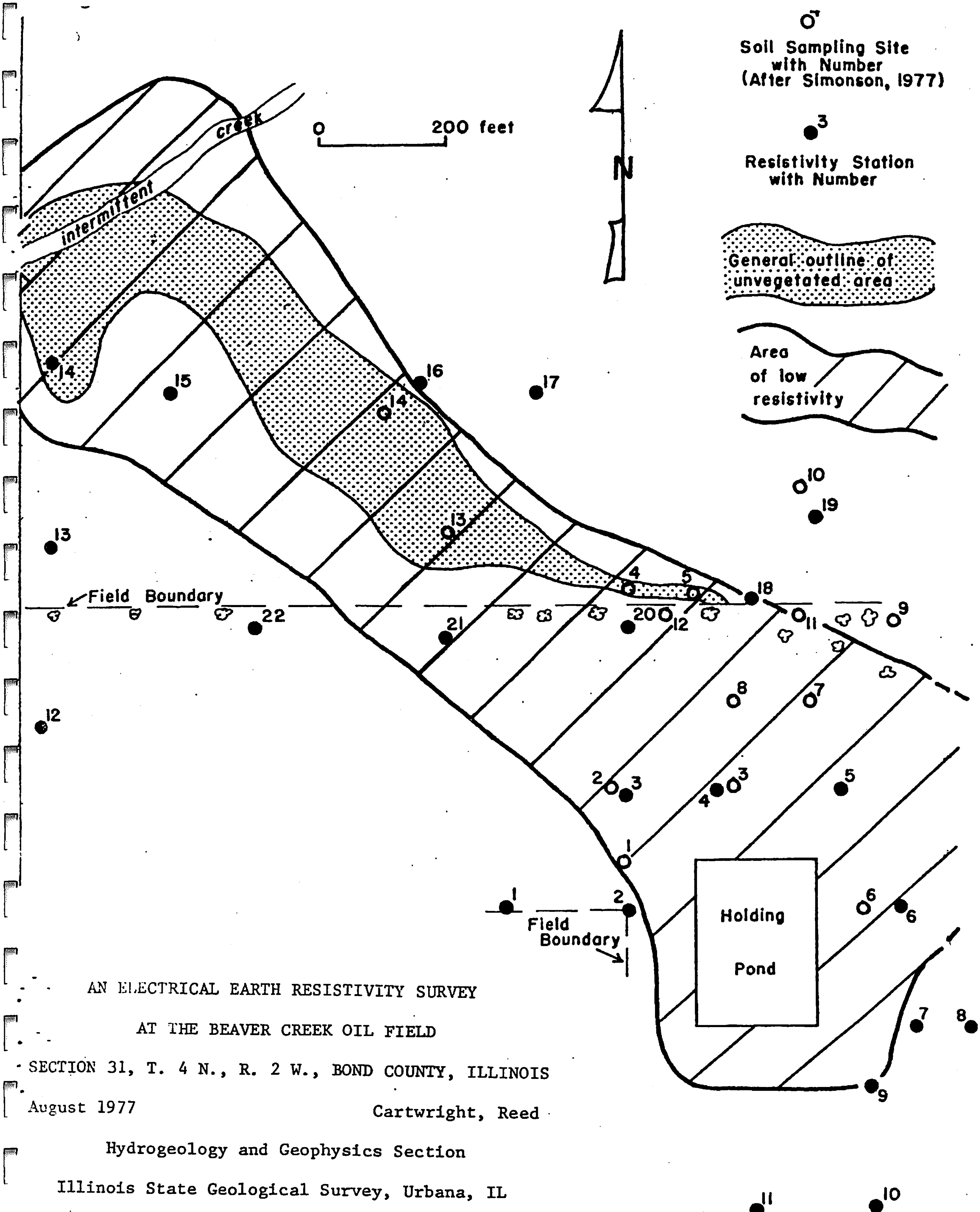
The second type of depth sounding profile is illustrated at station no. 14 where no reading could be obtained because of the accumulation of electrolites at the surface. Several attempts were made to obtain depth sounding in the unvegetated area between stations 14 and 16, but none could be obtained. Station no. 16 shows a similar low surface resistivity but the decrease is much less severe.

Discussion

The electrical earth resistivity data appears to verify the hydrogeologic evaluation based on topographic analysis and the regional geologic interpretations. This data shows that an electrolite, almost certainly salt water brine from the pit, is entering the ground-water system and moving northwestward toward the small creek. The brine would move downward from the pit and then laterally in the permeable Hagerstown beds. This is consistent with our interpretation of the resistivity data illustrated by the type of depth sounding profile at station no. 15, etc. In the lower unvegetated areas along the drainage swale and at the creek there would be an upward ground-water gradient bringing salts to the surface. This interpretation is supported by the electrical earth resistivity data around stations 14 to 16.

To travel from the pit to the creek, a distance of approximately 1500 feet, in 35 years, the water would have to be moving in a zone more permeable than normal clayey till. The sandy Hagerstown beds could provide such a zone of ground-water movement.

In summary, the electrical earth resistivity survey strongly suggests the presence of a wedge of salt water extending from the brine pit on the Follett lease northwest to the creek where the vegetation kill has occurred. This is consistent with the geology of the area and the generalized interpretation of the hydrogeology based on observations of the topographic relationships.



AN ELECTRICAL EARTH RESISTIVITY SURVEY

AT THE BEAVER CREEK OIL FIELD

SECTION 31, T. 4 N., R. 2 W., BOND COUNTY, ILLINOIS

August 1977 Cartwright, Reed

Hydrogeology and Geophysics Section

Illinois State Geological Survey, Urbana, IL

ILLINOIS STATE GEOLOGICAL SURVEY
NATURAL RESOURCES BUILDING, URBANA, ILLINOIS 61801 TELEPHONE 217 344-1481
Jack A. Simon, CHIEF

December 14, 1977

A RECONNAISSANCE ELECTRICAL EARTH RESISTIVITY SURVEY ON THE CHARLES VONDER HAAR FARM, SECTIONS 8 AND 17, T. 3 N., R. 2 W., CLINTON COUNTY, ILLINOIS

By

Philip C. Reed, Assistant Geologist
Keros Cartwright, Geologist and Head
Hydrogeology and Geophysics Section

At the request of Mr. George R. Lane, Department of Mines and Minerals, State Office Building, Springfield, Illinois, 62706, a reconnaissance electrical earth resistivity survey was made on November 3, 1977, on the Charles Vonder Haar Dairy Farm situated near the Keyesport Oil Field in the SW¼ Section 8 and the NE¼ Section 17, T. 3 N., R. 2 W., Clinton County, Illinois. Assisting in the field work were Mr. Leonard Sturm, 312 West Commerce, Grayville, Illinois, 62844, from the Department of Mines and Minerals and Mr. Charles Vonder Haar, R. R. #1, Carlyle, Illinois, 62231. A separate request by Mr. Charles E. Fisher, Jr., Oil Producer, Box 369, Mt. Carmel, Illinois, 62836, was received on November 14, 1977. Information on the location of abandoned oil wells and oil tests, producing and injection wells, and cultural features at and near the farm was furnished by Mr. Fisher. The purpose of the study was to determine the distribution of the salt water within the ground-water reservoir or aquifer utilized at the farm for water supply and if possible, to determine the origin of the salty water so that the water quality in the aquifer can be restored to the original condition. During the study, particular emphasis was made to resolve the question of whether the presence of salty water in the Vonder Haar farm well is related to disposal of brines by reinjection into the oil producing horizon.

Hydrogeologic Setting

The Vonder Haar farm is located at the northernmost part of the Keyesport Oil Field in a region of kame and esker-like hills on the Illinoian till plain west of the Carlyle Reservoir. A hill immediately south of the farm residence has about 20 feet of relief, while one mile to the north another hill rises about 50 feet above the till plain. Well logs from the Geological Survey files in the study area attached with this report give data on the earth materials in Sections 7, 8, 16, 17 and 18, T. 3 N., R. 2 W. The logs indicate that 20 to 60 feet of unconsolidated materials, primarily of glacial origin, overlie the Pennsylvanian-age bedrock. The bedrock consists of relatively impermeable shale and limestone with minor beds of sandstone and coal.

At the Vonder Haar farm, driller's logs and natural gamma logs (enclosed) run by the Geological Survey indicate that the glacial drift thickness is about 28 feet, consisting of about 6 to 18 feet of silty sandy clay which in turn is underlain

by as much as 14 feet of gravelly sand lying directly on the bedrock. Two large diameter water wells tapping the gravelly sand are utilized for supply on the farm. Well no. 1, completed in 1969, is situated about 400 feet north of the residence and well no. 2, completed in 1976, is located about 300 feet east of the residence. A large diameter well reported to be 14 feet deep is immediately west of well no. 1. On the hill immediately south of the farm in the Keyesport Oil Field in Section 17, T. 3 N., R. 2 W., the drift section reportedly consists of about 55 feet of clay and gravel. Regional stratigraphic studies by the Survey in the Carlyle area indicate that these glacial materials are associated with the Hagerstown Member of the Glasford Formation of Illinoian age. Hills mined for sand and gravel two miles north of the Vonder Haar farm are part of the Hagerstown Member.

The deposits of significance in this study are the permeable sand and gravel beds above the bedrock which form the ground-water reservoir at relatively shallow depths. These beds are subject to contamination while sources of pollution are available. Water entering the ground-water reservoir from rainfall will move from higher to lower elevations and eventually discharge into Allen Branch to the east or move westward toward the unnamed drainageway in Section 8. Similarly, oil field brines entering the ground-water reservoir from holding ponds would move outward from the upland areas into the lowland in the vicinity of the farm.

Resistivity Survey

The electrical earth resistivity survey is based on the principle that uncontaminated, compact glacial till, alluvial clay and shale present more resistance to the passage of electrical current than do sand and gravel, or sandstone and limestone of the bedrock. The passage of electrical current through earth materials is a property of the rock type and the water contained in rocks. Electric current introduced in earth materials containing water with a high concentration of soluble salts will have greatly reduced electrical resistance. This relationship has appeared in many published studies and has been used in electrical earth resistivity surveying to map contaminated ground water (see Illinois State Geological Survey Reprint 1972-U entitled Electrical Earth Resistivity Surveying in Landfill Investigations).

Collection of Field Data

During the study on the Vonder Haar farm, electrical depth sounding profiles were made at 29 resistivity stations using the Wenner electrode configuration. The locations of the resistivity stations are shown on an enlarged section of the Keyesport Quadrangle Topographic Map 7.5-minute series modified in part to conform to information supplied by Mr. Charles E. Fisher, Jr. Profiles of the depth soundings of each resistivity station are attached with this report. In normal uncontaminated, uniform materials the "a" spacing of the Wenner configuration is approximately equal to the depth of penetration of the electrical field. However, if a very conductive (low resistance) layer such as a salt water zone is present, the electrical field will be somewhat distorted reducing the depth of penetration.

Iso-resistivity contour maps showing apparent resistivity, were constructed for "a" spacing depths of 5, 10, 20 and 30 feet. These maps indicate a region of greatly depressed apparent resistivity surrounding the north part of the Keyesport Oil Field extending outward into the Vonder Haar farm. The contour map for the

20-foot "a" spacing is included with the modified quadrangle map of this report. Station nos. 1, 2, 3, 10, 14, 15, 16, 18, 19, 26 and 27 are affected by highly conductive materials, presumably saltier water. These stations are in contrast to station nos. 7, 17, 21, 22 and 23 where readings are near normal due to little or no accumulation of electrolites in the earth materials. The relationship between the apparent resistance of the aquifer materials and their contained water near the pumped wells on the Vonder Haar farm is given below using Illinois State Water Survey water analyses (enclosed) from wells 1 and 2 and a well of similar depth on the Olsen farm (obtained in 1970) about one mile north from the contaminated area.

	Apparent Resistivity (ohm meters) 20-foot "a" spacing	Chloride Concentration (Cl)
Well #1	15	1060
Well #2	20	150
Olsen Well	25 (estimated)	64

These data demonstrate the relationship between the apparent resistivity and chloride ion concentrations present in the drift aquifer. As the chloride concentration diminishes the apparent resistivity increases due to the lower concentration of soluble salts.

Conclusion

The electrical earth resistivity survey data are in agreement with the hydrogeologic evaluation in the study area based on the topographic analysis of the regional and on site geologic interpretation. Information collected during the study shows the presence of a circular wedge of salt water around the abandoned brine holding ponds extending from the ponds along the north perimeter of the Keyesport Oil Field into the Charles Vonder Haar farm lot area. There are no data which show conclusively whether the reinjection of produced brine is or is not related to the water quality problem on the farm.

The presence of poor quality water on the Vonder Haar farm may have resulted for one or more of several possible explanations. They are listed below in the order from those we think most likely to those least likely:

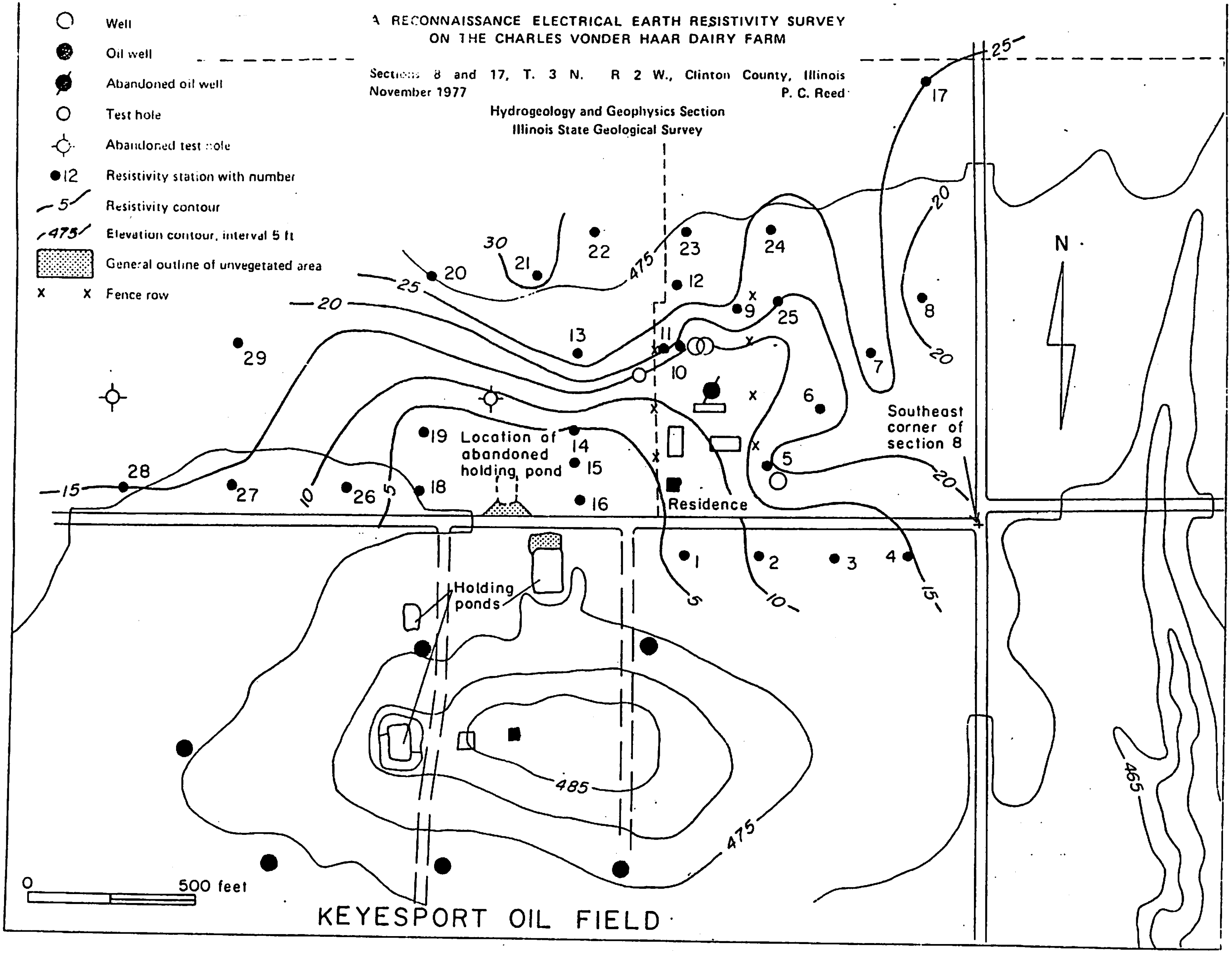
(1) The data from the resistivity survey clearly show that the abandoned brine holding ponds leaked salt water to the shallow aquifer and spread outward. The two wells on the Vonder Haar farm are within the region of depressed electrical earth resistivity values. There was sufficient time for the salt water to spread from the ponds to the Vonder Haar farm during their long period of use. Abandonment of the ponds will allow the quality of water in the aquifer to slowly recover; meanwhile, the salt water already in the aquifer will continue to spread and continue to be diluted by rainfall.

(2) The Vonder Haar wells are in or very near the animal lot. The presence of cattle is commonly associated with high chloride water which originates in the animal waste. The large diameter dug or bored wells are particularly vulnerable to nearby surface sources of pollution. These wells, especially the old dug ones, are difficult to seal. In addition, the thin, surficial loess affords only moderate protection of the aquifer. The shape of the 15 ohm-meter line is similar to the outline of the animal lot.

(3) Repressuring the production by reinjection of the produced brine may force salt water up an unplugged abandoned well. According to Mr. Fisher, three wells were originally drilled on the Vonder Haar farm; two were dry and plugged, a third located in or near the farm lot produced oil but was reported abandoned and plugged in October 1953. According to Mr. Fisher, the farmer on the property several years ago took out or broke off the surface casing. The Survey has no other records of deep wells drilled on the property. However, if there are unknown wells with broken seals, water could leak upward producing a low resistivity ring around the leaking well. No rings were observed with the station spacing that was used. A small bulge in the coutour interval is present northeast of the farm log and the abandoned well, but there is no indication that this bulge is the result of leakage from an abandoned oil well.

(4) The combination of leakage in one or more of the wells in the oil field to the south, and/or the pumpage of the farm wells may increase the rate of salt water migration, thus causing water quality in the farm wells to deteriorate more rapidly.

In summary, the most likely source of salt water in the well on the Vonder Haar farm is water migrating from the old brine holding ponds abandoned over two years ago. The problem may also be aggravated by waste products from animals on the property, possible leakage from abandoned wells with broken seals or unknown and unplugged wells, or by injection in and/or pumping of existing wells.


A RECONNAISSANCE ELECTRICAL EARTH RESISTIVITY SURVEY
ON THE CHARLES VONDER HAAR DAIRY FARM
Sections 8 and 17, T. 3 N. R 2 W., Clinton County, Illinois
November 1977
P. C. Reed
Hydrogeology and Geophysics Section
Illinois State Geological Survey
Well
Oil well
Abandoned oil well
Test hole
Abandoned test hole
12 Resistivity station with number
5 Resistivity contour
475 Elevation contour, interval 5 ft
General outline of unvegetated area
x x Fence row
N
Location of abandoned holding pond
Residence
Southeast corner of section 8
Holding ponds
485
475
465
0 500 feet
KEYESPORT OIL FIELD

	WELL #1 SECTION 8, T. 3 N., R. 2 W. 1977		WELL #2 SECTION 8, T. 3 N., R. 2 W. 1977		WELL SECTION 9, T. 3 N., R. 2 W.	
	NOV.	DEC.	NOV.	DEC.	1970	1977
NITRATE (NO_3)	0.4*	1.2	0.9	5.2	2.6	1.0
CHLORIDE (Cl)	1060	750	150	2100	64	40
ALKALINITY (HCO_3)	318	400	9.5	390	568	600
TOTAL HARDNESS ($CaCO_3$)	920	725	358	1500	662	250
TOTAL DISSOLVED SOLIDS	2105	1500	362	3700	906	610

* VALUES REPORTED IN MILLIGRAMS PER LITER (MG/L)

ILLINOIS STATE GEOLOGICAL SURVEY
NATURAL RESOURCES BUILDING, URBANA, ILLINOIS 61801 TELEPHONE 217 344-1481
Jack A. Simon, CHIEF

August 22, 1977

A RECONNAISSANCE ELECTRICAL EARTH RESISTIVITY SURVEY AT THE COUNTRY TRAILS SUBDIVISION #1, SECTION 34, T. 15 N., R. 4 W., SANGAMON COUNTY, ILLINOIS

By

Philip C. Reed, Assistant Geologist
Hydrogeology and Geophysics Section

Introduction

At the request of Mr. Murray Williams, Greene and Meador, 202 West Park Street, Taylorville, Illinois, 62568, a brief electrical earth resistivity survey was made at the Country Trails Subdivision owned by Mr. Bud Hunter on August 10, 1977. The purpose of the survey was to determine the distribution of a salt water wedge at the subdivision. An abandoned brine pit located adjacent to the eastern edge of the subdivision is no longer in use. Four large diameter water wells drilled on lots 7, 8, 10 and 11 were reported to have chloride concentrations ranging from 250 to over 33,000 mg/l (milligrams per liter).

Hydrogeologic Setting

The subdivision is situated in the upland and lowland areas of the Sangamon River Valley 540 to 585 feet above mean sea level near an active oil field. The ice deposited materials (glacial drift) of Illinoian age overlying the bedrock of Pennsylvanian age consist of a pebbly clay material, called till, with some thin, discontinuous beds of sand and gravel. Most of the wells in the area are large diameter bored wells open to the drift that produce only small and often seasonal amounts of water. The contact between the glacial drift and the underlying bedrock is marked by a line of glacial boulders along the road near the western margin of lot no. 1 at an elevation of approximately 545 feet above mean sea level. The bedrock consists primarily of shale with some thin, discontinuous beds of limestone and sandstone, not generally considered an aquifer in this area. Below a depth of 200 feet water from the bedrock may become too mineralized for most uses.

Resistivity Survey

The electrical earth resistivity survey is based on the principal that uncontaminated, compact glacial till, clay-alluvium and shale present less resistance to the passage of an electrical current than do sand and gravel or sandstone or limestone of the bedrock. Electrical current introduced in earth materials with high sodium chloride concentrations will have a greatly reduced resistance. The

accompanying map shows the location of the 21 stations occupied during the course of the survey. All stations are marked with numbered wooden stakes driven in the ground.

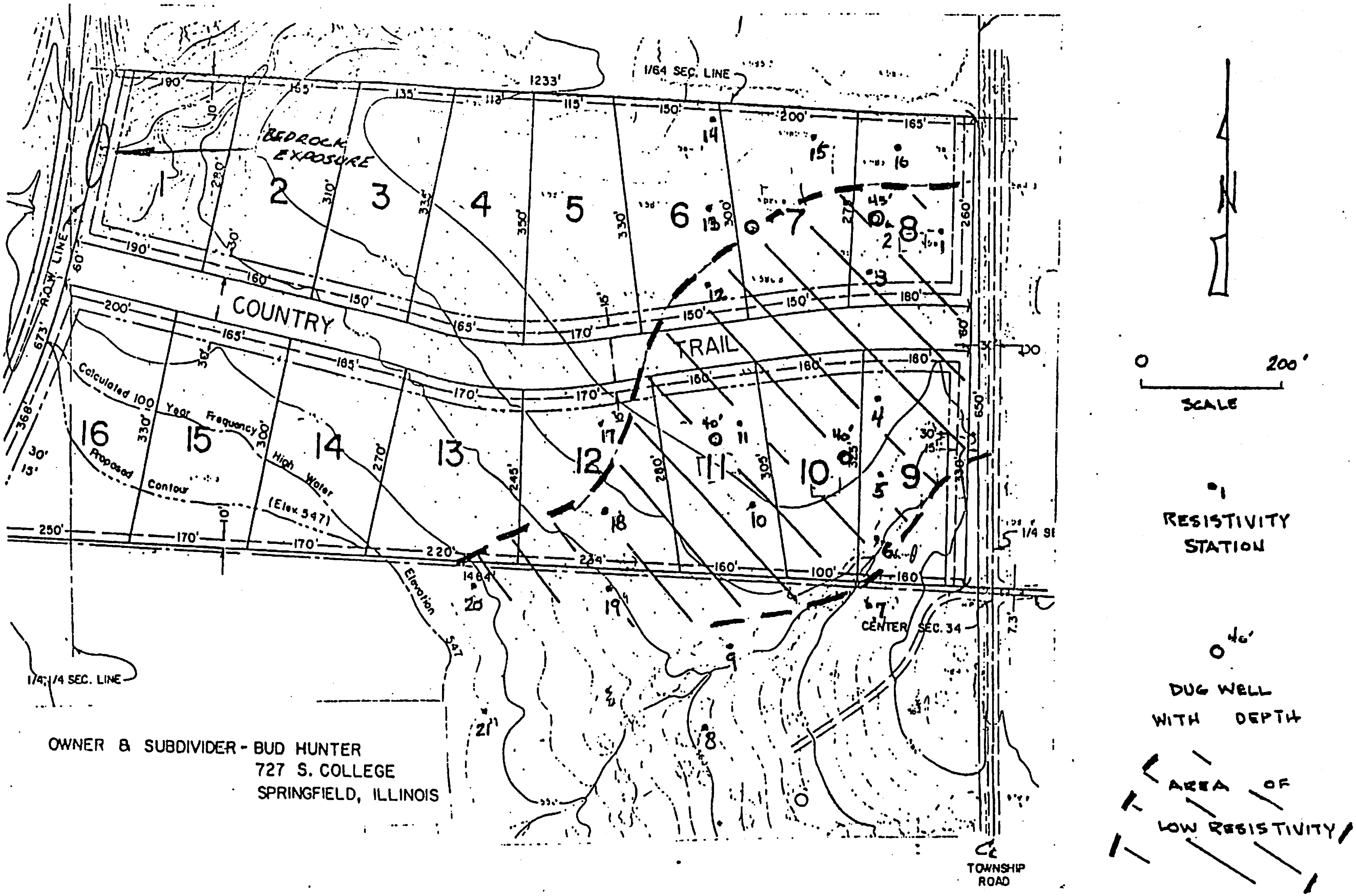
Conclusion

This study demonstrated the usefulness of an electrical earth resistivity survey in describing oil field contamination due to salty water. The outline of a low or reduced resistivity area is shown by the hachured pattern on the map. This area of low resistivity correlates well with the reported chloride concentrations from the large diameter wells in the study area and depicts the movement of the salty water above the bedrock toward the lowland.

Information from drillers' logs supplied by Reynold Well Drilling, Inc., in conjunction with the geologic setting, suggests that yields from individual large diameter wells constructed in the drift materials above the bedrock at the subdivision may fluctuate greatly seasonally and that wells of this type are only a short term solution to the water supply problem present at the subdivision. A more desirable and lasting source of ground water may be present in the alluvial materials of lowland of the Sangamon River Valley possibly within the limits of the subdivision.

Driller's logs of formation changes in color and texture and sample cuttings taken at regular five-foot intervals should be sent to the State Geological Survey for study and interpretation. Sample sacks and log books will be furnished free of charge upon request.

Any future correspondence referring to this report should be addressed to the State Geological Survey, Urbana, Illinois, 61801.



AN ELECTRICAL EARTH RESISTIVITY SURVEY AT COUNTRY TRAILS SUBDIVISION
SECTION 34, T.15N., R.4W., SANGAMON COUNTY, ILLINOIS

AUGUST 1977 P.C. REED

HYDROGEOLOGY AND GEOPHYSICS SECTION
ILLINOIS STATE GEOLOGICAL SURVEY, URBANA, ILLINOIS 61801

ILLINOIS STATE GEOLOGICAL SURVEY
NATURAL RESOURCES BUILDING, URBANA, ILLINOIS 61801 TELEPHONE 217 344-1481
Jack A. Simon, CHIEF

August 7, 1975

AN ELECTRICAL EARTH RESISTIVITY SURVEY ON AN OIL LEASE OF BERNARD PODOLSKY, WHITE COUNTY, ILLINOIS

By

Philip C. Reed, Assistant Geologist
Hydrogeology and Geophysics Section

At the request of Mr. Bernard Podolsky, P. O. Box 278, Fairfield, Illinois, 62837, an electrical earth resistivity survey was conducted on an oil lease located in the W½ of Section 27, T. 3 S., R. 9 E., White County, on June 18 and 26, 1975. The purpose of the survey was to better define the source and occurrence of the contamination of the earth materials by salt water at the lease so that the land could be returned to its original state.

The Problem

The problem that exists at the oil lease in Section 27, T. 3 S., R. 9 E., is the contamination of the earth materials by oil field brines associated with oil production. Injection of the brines in the vicinity of the abandoned oil well and the spilling of the brines in waterways near the abandoned oil well from pre-existing storage pits have contaminated the area around parts of the lease. The principal storage pit, which was filled in last fall, was located southwest of the abandoned well shown on the enclosed sketch map. Vegetation will not grow in areas around the pits and in drainageways where the salt concentration is too high.

Geological Situation

The oil lease is situated in the upland area eight miles northwest from the confluence of the Skillet Fork and the Little Wabash River within the Golden Gate Consolidated oil field. Wells in this part of the field generally produce from Mississippian sands and limestones in the depth range of 3000 to 3500 feet. The drift materials overlying bedrock of Pennsylvanian age range in thickness from about 10-25 feet and consist primarily of Illinoian-age till. The best exposures present in the request area are at the salt spring and pond. Here, rubble of siltstone and sandstone of Pennsylvanian bedrock, litter the pebbly clay walls of the pond. Silt pockets appear to be present within the pebbly clay glacial materials higher in the section, especially where a water line crosses the road and enters the pond from the tank battery. The pebbly clay till is overlain by as much as two feet of loessial silt in the upland of the study area.

The physical features, which are shown on the sketch map, of the study area are: 1) the abandoned McClosky oil well, Moses and Stewart #1 constructed with 45 feet of surface casing in 1952; 2) a salt water injection well completed to a depth of 950 feet; 3) a tank battery consisting of three 210 barrel tanks and an oil-water separation unit; 4) a house owned by George Lamont; and 5) a brine-evaporation pit recently filled and leveled to conform with the original land surface.

Hydrogeologic Features

The hydrogeologic features within the study area, which are shown on the sketch map, are: 1) a pond and a salt spring northwest of the Lamont house; 2) a pond east of the house; 3) a cistern about 8.5 feet deep on the north side of the house; 4) a network of ditches trending north, west and east, and generally away from the upland area where the abandoned oil well and injection well are situated; and 5) an area without vegetation covered in part with what appears to be white salt crystals.

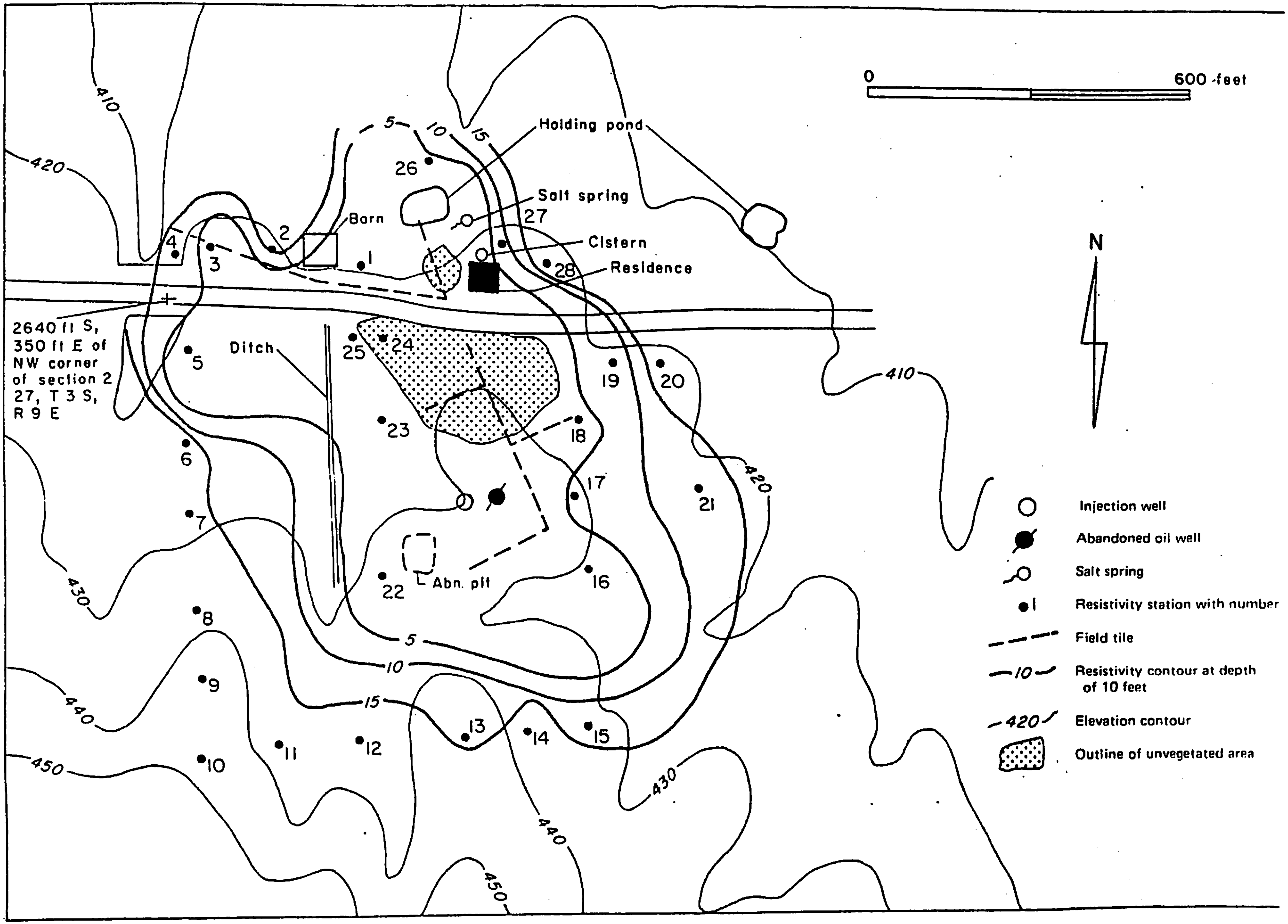
Resistivity Survey

The electrical earth resistivity survey is based on the principle that uncontaminated, compact glacial till, alluvium and shale present less resistance to the passage of an electric current than do uncontaminated sand and gravel or sandstone or limestone of the bedrock. Electrical current introduced in earth m materials with high chloride ion concentrations in the water will greatly reduce the resistance so that the instrumentation of a resistivity survey frequently will not detect any reading at all. As the chloride ion concentrations are reduced in the earth materials, the instrumentation becomes more sensitive, measuring progressively higher levels of resistance as the contamination or chloride ion concentration decreases. The accompanying sketch map shows the approximate location of the 28 stations occupied in the course of the survey. All stations are marked by numbered wooden stakes driven into the ground

Conclusion

The maps showing isoresistivity values of 15 and 20 ohm-meters at depths 10, 20 and 30 feet below land surface, depict the effect of the oil field wastes and their movement and dilution due to rainfall outward from the primary area of contamination near the covered disposal pit, the brine injection well, and abandoned oil well. The resistivity readings correlate with the enclosed water analyses made from water collected during the course of work at the request area.

This study demonstrated the usefulness of an electrical earth resistivity survey in describing oil field contamination due to salty water. No point source was found; however, the general outline of the contaminated area was established.



0
600 feet
N
Holding pond
Salt spring
Barn
Cistern
Residence
Ditch
Abn. pit
2640 ft S,
350 ft E of
NW corner
of section 2
27, T 3 S,
R 9 E
410
420
430
440
450
5
10
15
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28
Injection well
Abandoned oil well
Salt spring
Resistivity station with number
Field tile
Resistivity contour at depth of 10 feet
Elevation contour
Outline of unvegetated area

1975	POND	SEEP	CISTERN SURFACE	CISTERN BOTTOM 8.5'	RUPTURED TANK
CHLORIDE (Cl)	16,800*	18,400	200	360	13,800
TOTAL DISSOLVED SOLIDS	30,800	34,200	400	780	24,100
pH	7.55	7.34	8.47	7.21	7.51

1977	FIELD TILE				
CHLORIDE (Cl)	6,000	16,400		140	
TOTAL DISSOLVED SOLIDS	10,600	27,600		330	
pH	4.98	6.16		7.51	

* VALUES REPORTED IN MILLIGRAMS PER LITER (MG/L) SECTION 27, T. 3 S., R. 9 E.

APPENDIX C

Christian County
E.E.R. and Water Table Maps
Lithologic and Gamma Ray Logs

Christian County Holding Pond Study Site
Land Owner: Mr. J. David Myers
Operator: Mr. E. H. Kaufman
Pond Size: 30'x100'. Date Constructed: 1954?
Present Salt Water Input: None (Reportedly as much as 100 bbls/day prior to 1977)

Geologic Setting

The Christian County study site is located on an Illinoian till plain in Section 20, T. 13 N., R. 11 E., within the Assumption Consolidated Oil Field. The land elevation is estimated to be between 615-620 feet above mean sea level. Drainage is locally toward a swale north of the pit but generally southeastward toward a tributary of Oak Branch Creek. The unconsolidated Illinoian glacial drift and the more recent deposits of loess consist of sand, silt and glacial till about 80 feet thick and form a broad, flat plain in this area. Beneath these deposits is bedrock of Pennsylvanian age.

Hydrogeology

The surficial material at the site consists of about 5 feet of loessial silt and sand which forms part of the soil in this region. Bleached silt, sand and clay till form part of the surface spoil materials around the unvegetated areas of the pit. Beneath the loess is about 15 feet of silt and very fine to fine-grained sand of the Hagarstown Member of the Illinoian Glasford Formation. Below the Hagarstown, in decending order, are the Radnor and Smithboro Members of the Glasford Formation. The units consist of compacted sandy till and compacted clay till and probably extend to the underlying Bond Formation of Pennsylvanian age.

The silt and sand of the Hagarstown Member are the principal source of ground water in the area and are less compact than the underlying till of the Radnor Member (see compressive strength measurements).

Hydrology

Water level contours around the hold pond indicate a ground-water mound beneath the holding pond with the regional water level surface trending away from

the upland toward the lowland areas.

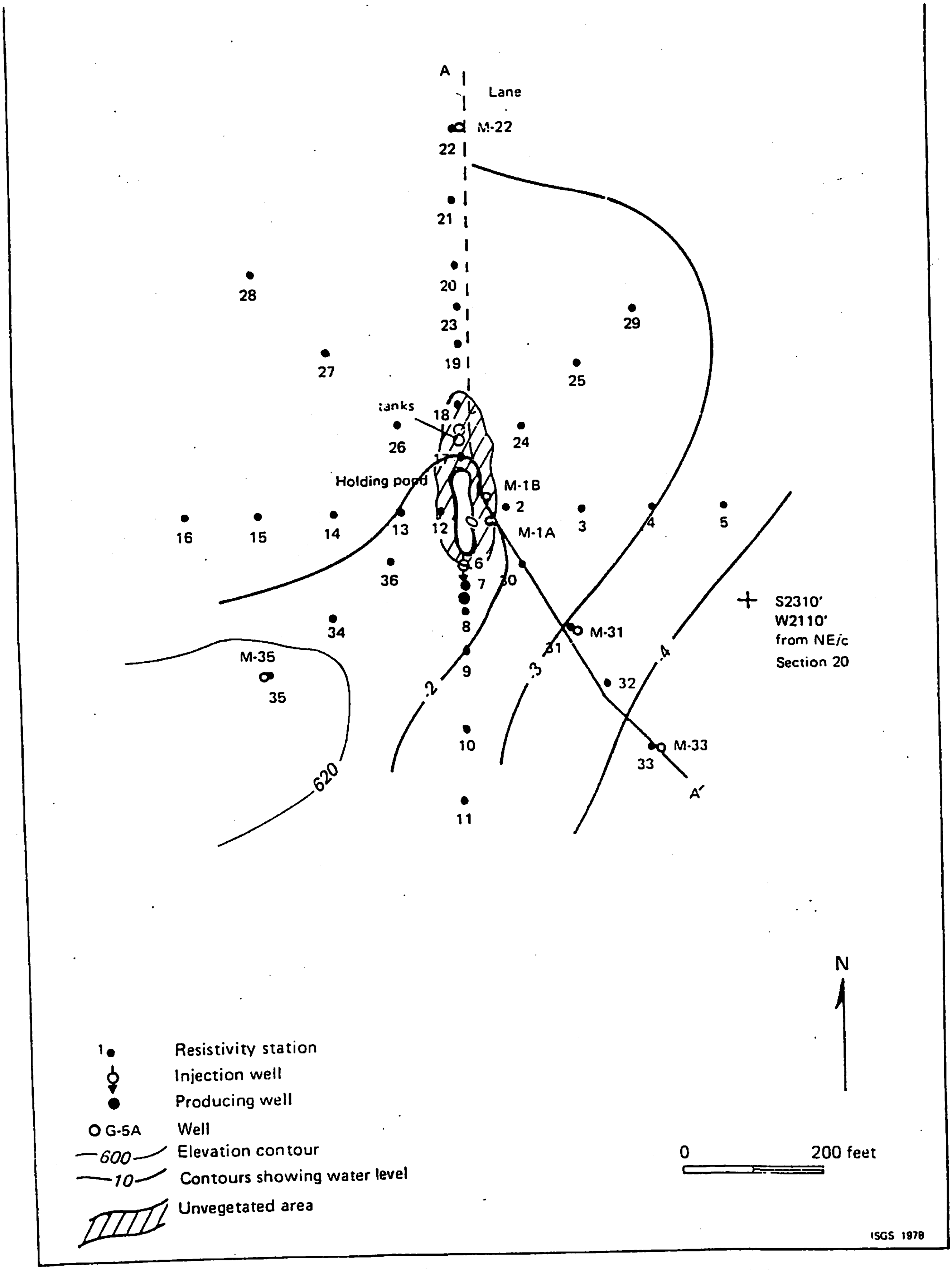
The isoresistivity contours also indicate the migration of chlorides to be greatest northward and southeastward.

The extent of the unvegetated area is depicted clearly on the photographs in the report. This area was often moist in many places, particularly after a rainfall event, suggesting that holding pond water is migrating laterally.

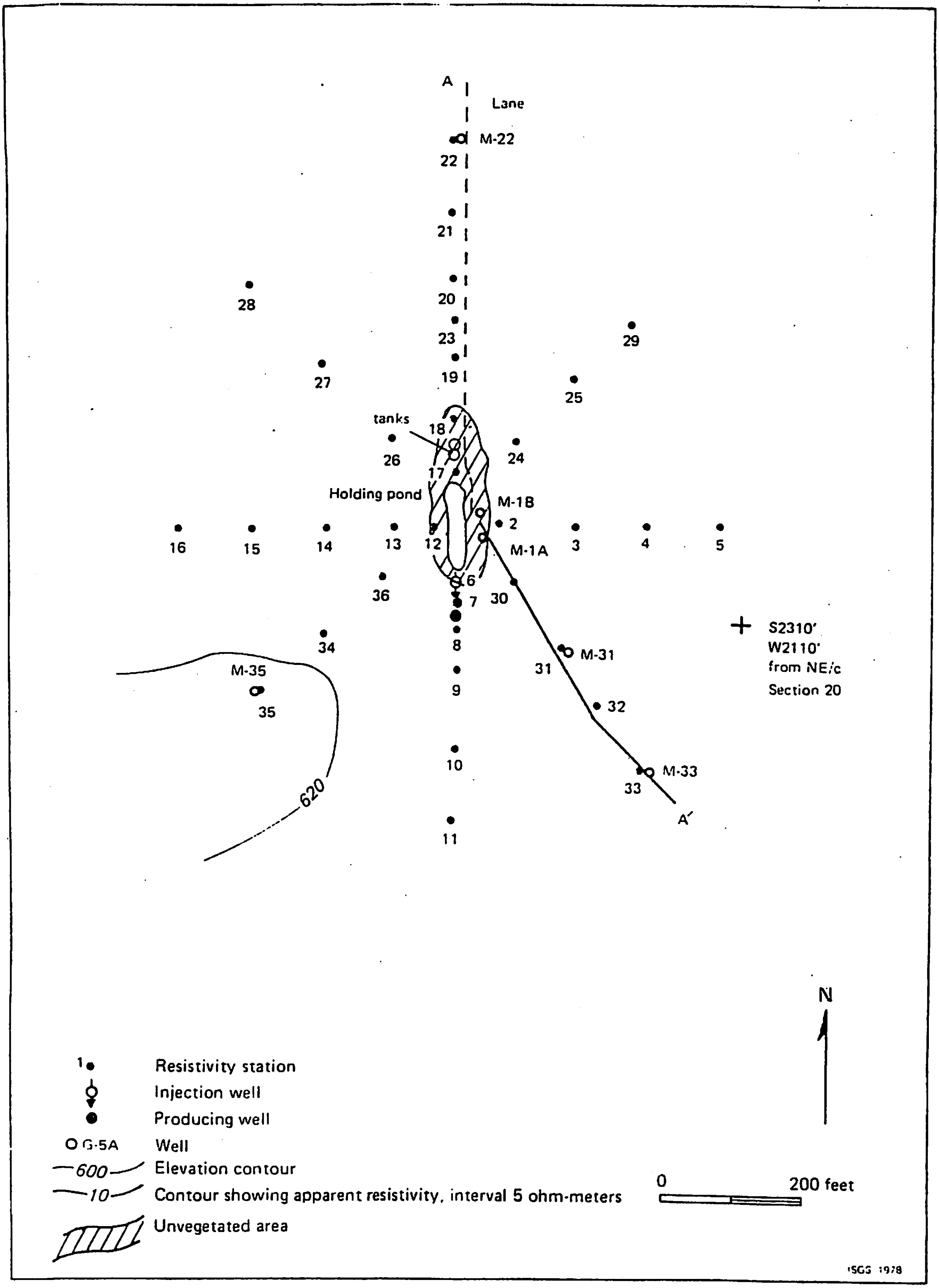
Apparent resistivity values from split spoon samples were much higher below the Hagarstown Member, probably indicating little downward movement of the highly mineralized water.

C H R I S T I A N   C O U N T Y

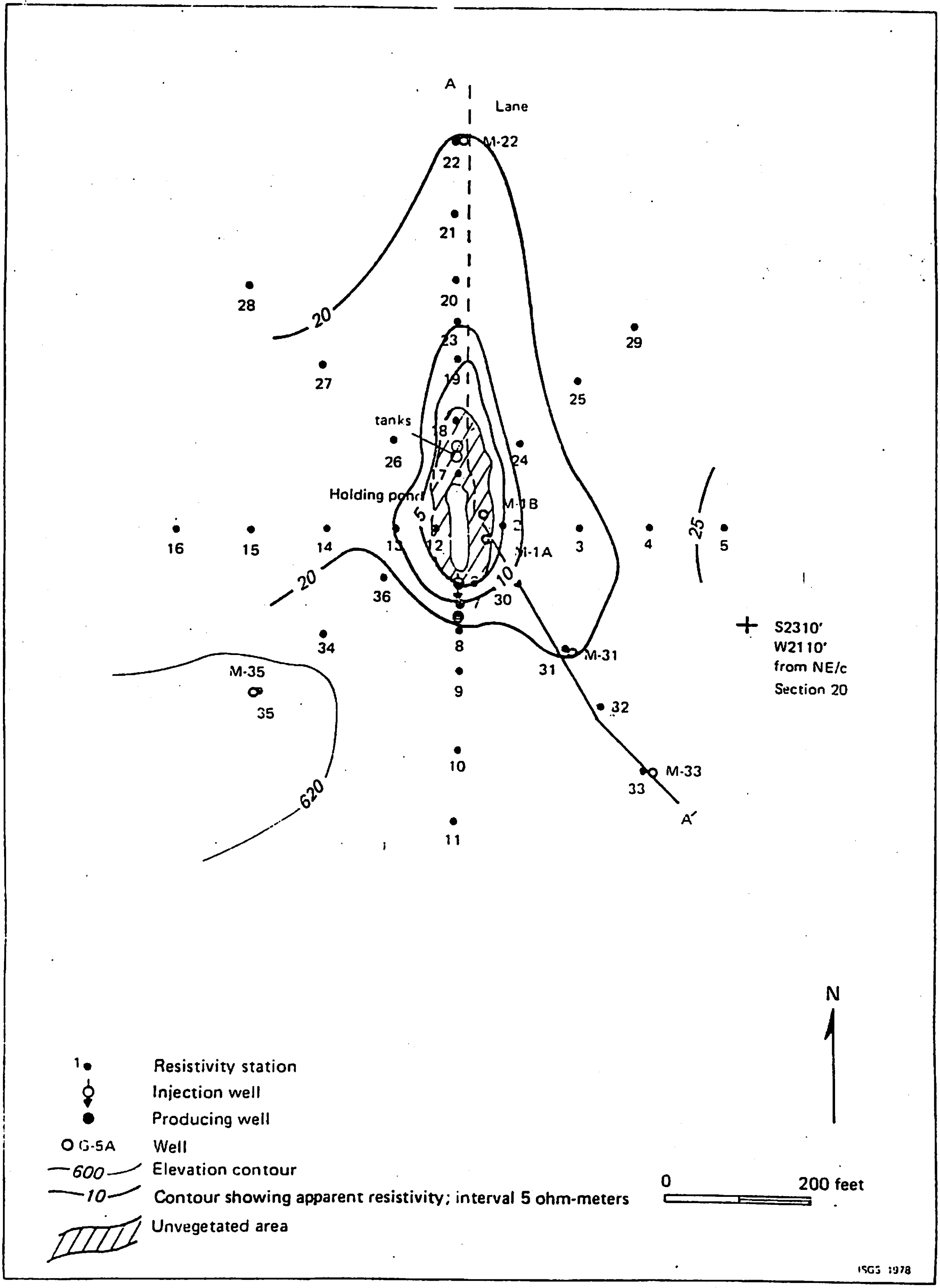
Well No.	Slot Interval	Relative Height Casing	Static Level Below Top Of Casing, July 20, 1978	Height Casing Above Ground	Relative Ground Level At Well	Static Level Below Ground	Ground Level Relative To Datum	Water Levels Relative To Ground Level Datum
M-1A	9-19	-	1,83	.10	5,08	-1,73	0,0	+(-1,73)=-1,73
M-1B	4-9	-	2,65	,35	5.15	-2,30	-0,07	+(-2,30)=-2,37
M-22	9-19	-	3,37	,11	4,91	-3,26	+0,17	+(-3,26)=-3,09
M-31	10-20	-	4,28	,32	4,28	-3,96	+0,80	+(-3,96)=-3,16
M-33	9-19	-	3,89	,60	6,18	-3,29	-1,10	+(-3,29)=-4,39
M-35	10-20	-	5.40	,70	1,49	-4,70	+3,59	+(-4,70)=-1,11
Fluid Level in Pit					5,18			-0,10



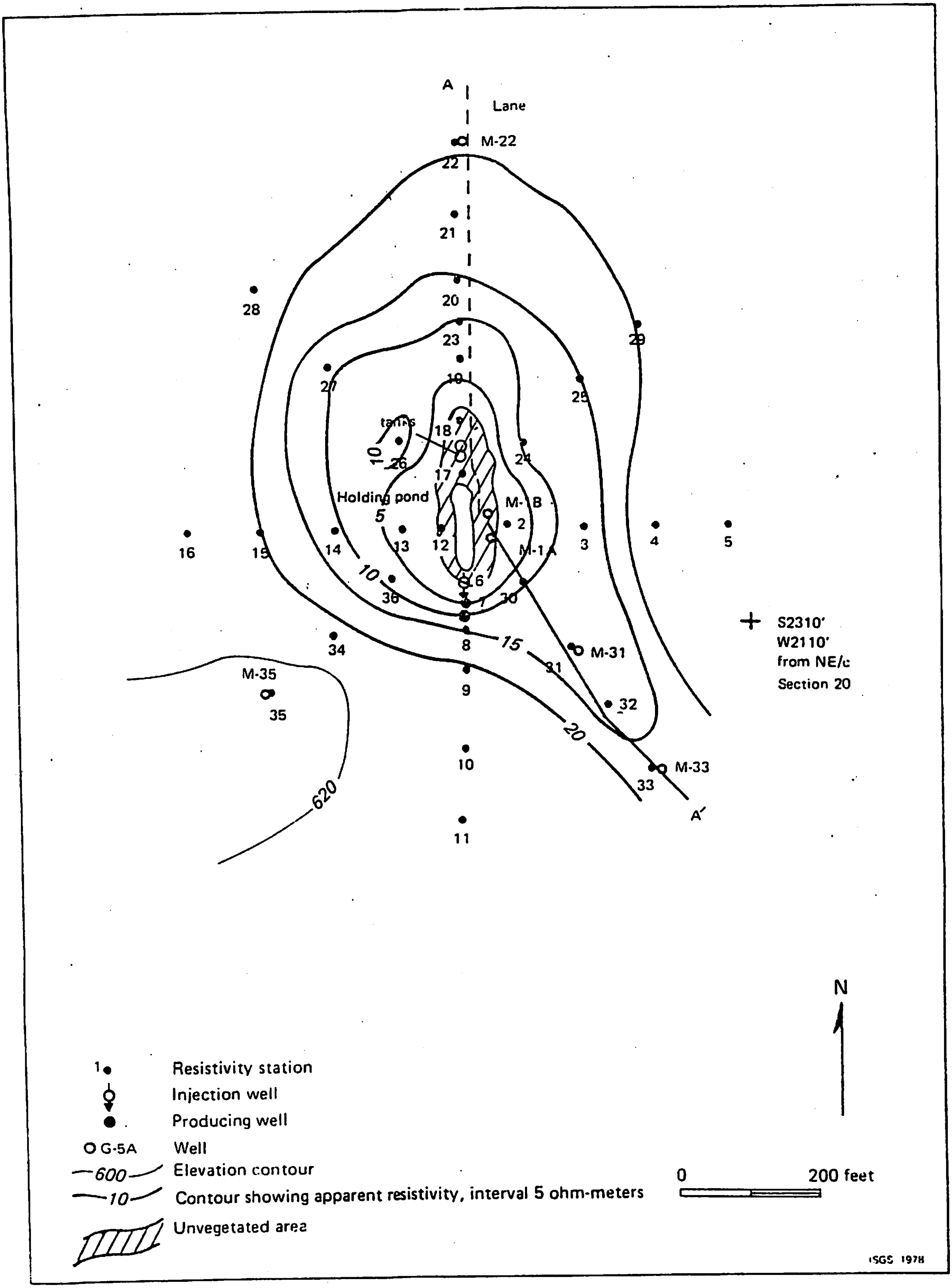
WATER LEVEL CONTOURS (DATUM GROUND LEVEL, M-1A)
AT THE ASSUMPTION CONSOLIDATED OIL FIELD
Section 20, T. 13 N., R. 1 E., Christian County, Illinois
July 1978—Murphy, Osby (IEPA); Reed (ISGS)



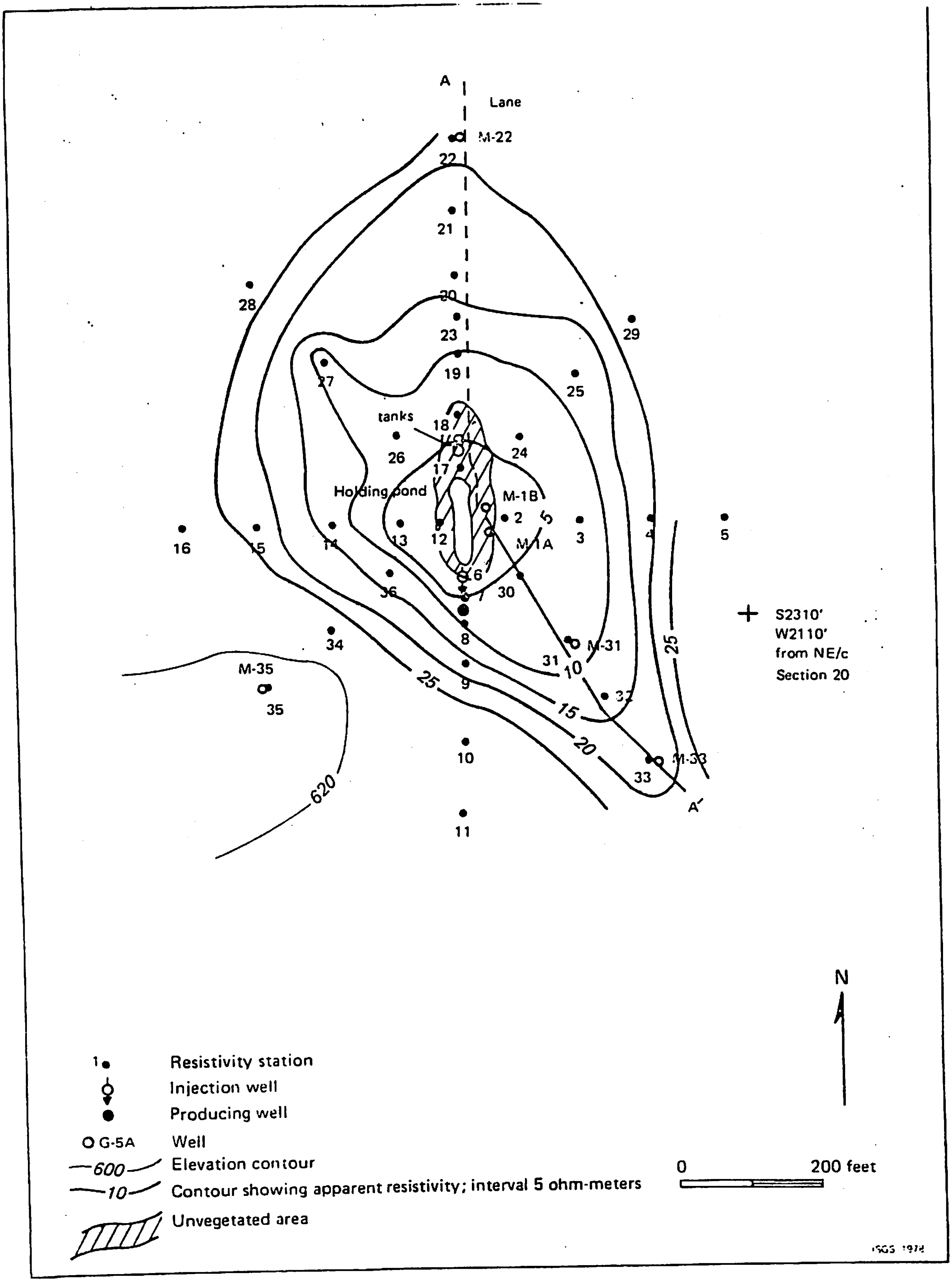
AN ELECTRICAL EARTH RESISTIVITY SURVEY
AT THE ASSUMPTION CONSOLIDATED OIL FIELD
Section 20, T. 13 N., R. 1 E., Christian County, Illinois
July 1978—Murphy, Osby (IEPA); Reed (ISGS)



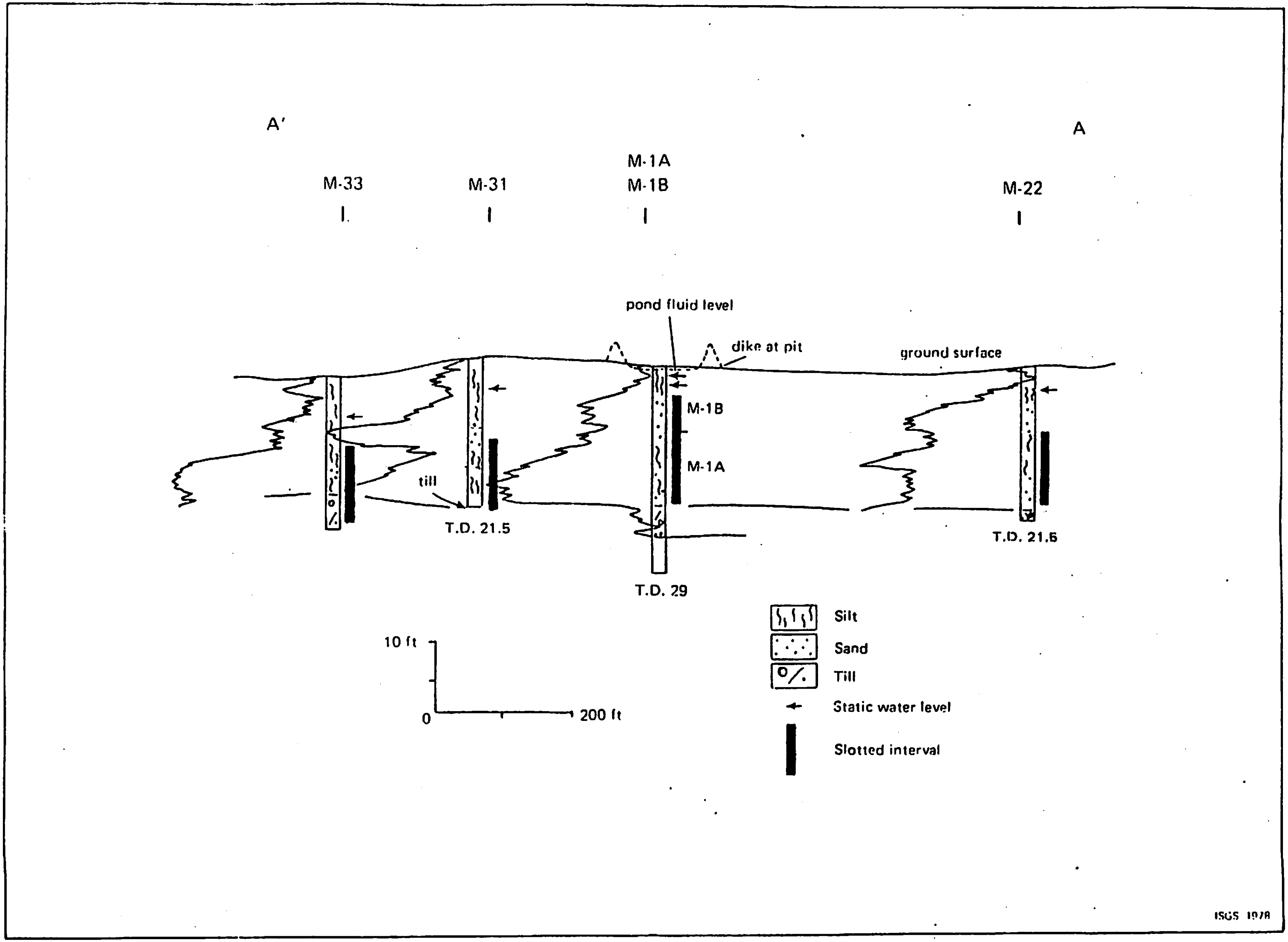
APPARENT RESISTIVITY (OHM-METERS) AT 5-FOOT DEPTH
AT THE ASSUMPTION CONSOLIDATED OIL FIELD
Section 20, T. 13 N., R. 1 E., Christian County, Illinois
July 1978—Murphy, Osby (IEPA); Reed (ISGS)



APPARENT RESISTIVITY (OHM-METERS) AT 10-FOOT DEPTH
AT THE ASSUMPTION CONSOLIDATED OIL FIELD
Section 20, T. 13 N., R. 1 E., Christian County, Illinois
July 1978–Murphy, Osby (IEPA); Reed (ISGS)



APPARENT RESISTIVITY (OHM-METERS) AT 20-FOOT DEPTH
AT THE ASSUMPTION CONSOLIDATED OIL FIELD
Section 20, T. 13 N., R. 1 E., Christian County, Illinois
July 1978–Murphy, Osby (IEPA); Reed (ISGS)



GEOLOGIC SECTION AT THE ASSUMPTION CONSOLIDATED OIL FIELD
Section 20, T. 13 N., R. 1 E., Christian County, Illinois
June 1978—Reed (ISGS)

APPENDIX D

Bond County
E.E.R. and Water Table Maps
Lithologic and Gamma Ray Logs

Bond County Holding Pond Study Site
Land Administrator: Roger Riedemann
Operator: Clyde Bassett
Pond Size: 100'x100'. Date Constructed: 1940?
Present Salt Water Input: 150 barrels per day four days a month

Geologic Setting

The Bond County holding pond study site is located in Section 10, T. 6 N., R. 2 W., Bond County, Illinois, in the Woburn Consolidated Oil Field. The land elevation is between 565-580 feet above mean sea level. Drainage is generally westward toward a north flowing tributary to Gilham Creek. The study site is a part of a relatively flat and featureless drift plain underlain by Illinoian glacial deposits. The unconsolidated glacial drift and overlying deposits of loess consist of about 80 feet of clayey silt, sand, and till. Beneath these deposits is bedrock of Pennsylvanian age.

Hydrogeology

The surface materials exposed at the site consist of about 2 feet of Wisconsinan loessial silt and sand which form part of the soil in the region. Below the loess, exposed along the drainageways west and north of the pond, is the Hagarstown Member of the Illinoian Glasford Formation, An abandoned pond directly south of the active pond has been breached by an erosional waterway to a depth of 6 - 7 feet (see photographs). In the pond areas, the Hagarstown extends to about 20 feet below the land surface and consists primarily of sandy silt with minor amounts of sandy ablation till. The silt is differentially weathered, having undergone two periods of soil genesis. The Hagarstown Member is underlain by about 20 feet of the Vandalia Member of the Glasford Formation, a sandy till with a few thin sand layers. Beneath the Vandalia Member is about 30 feet of silty, smooth textured till assigned to the Smithboro Member of the Glasford Formation. The

lowermost 8 feet of glacial drift consists of dense Kansan till overlying the Bond Formation of Pennsylvanian age.

The silt, sand, and sandy till of the Hagarstown Member contain greater amounts of coarse clastic material, are less compact (see unconfined compressive strength measurements), and are relatively more permeable than the remaining tills of the Glasford Formation. The best exposure of Hagarstown is on the west side of the active holding pond. Here, about 8 feet of continually moist, unvegetated silt extends from the diked part of the pond, ending abruptly at the waterway (see photograph).

Hydrology

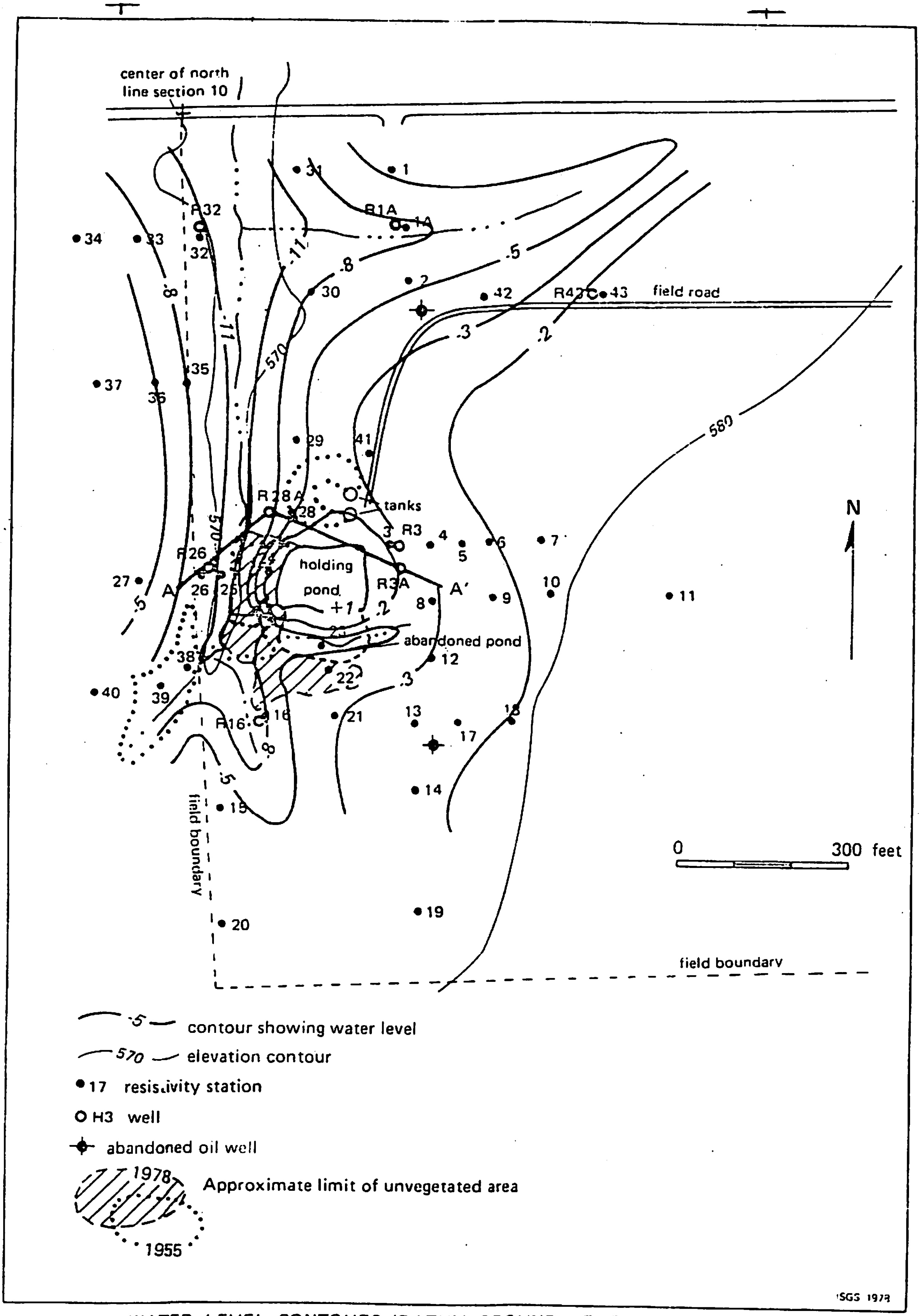
Water level contours at the hold pond reveal a ground-water mound superimposed on a water level surface which increases in gradient toward the drainageway. Water from the mound appears to seep regularly from the west side of the active pond dike into the waterway.

The distribution of apparent resistivity contours indicate the greatest migration of chlorides northward and westward toward drainageways. The extent of unvegetated areas surrounding the holding pond in 1978 is very similar to the area shown on the 1955 aerial photograph accompanying this report. The unvegetated area stops dramatically at the waterway, suggesting change of the flow pattern in this area (see Fig. 1).

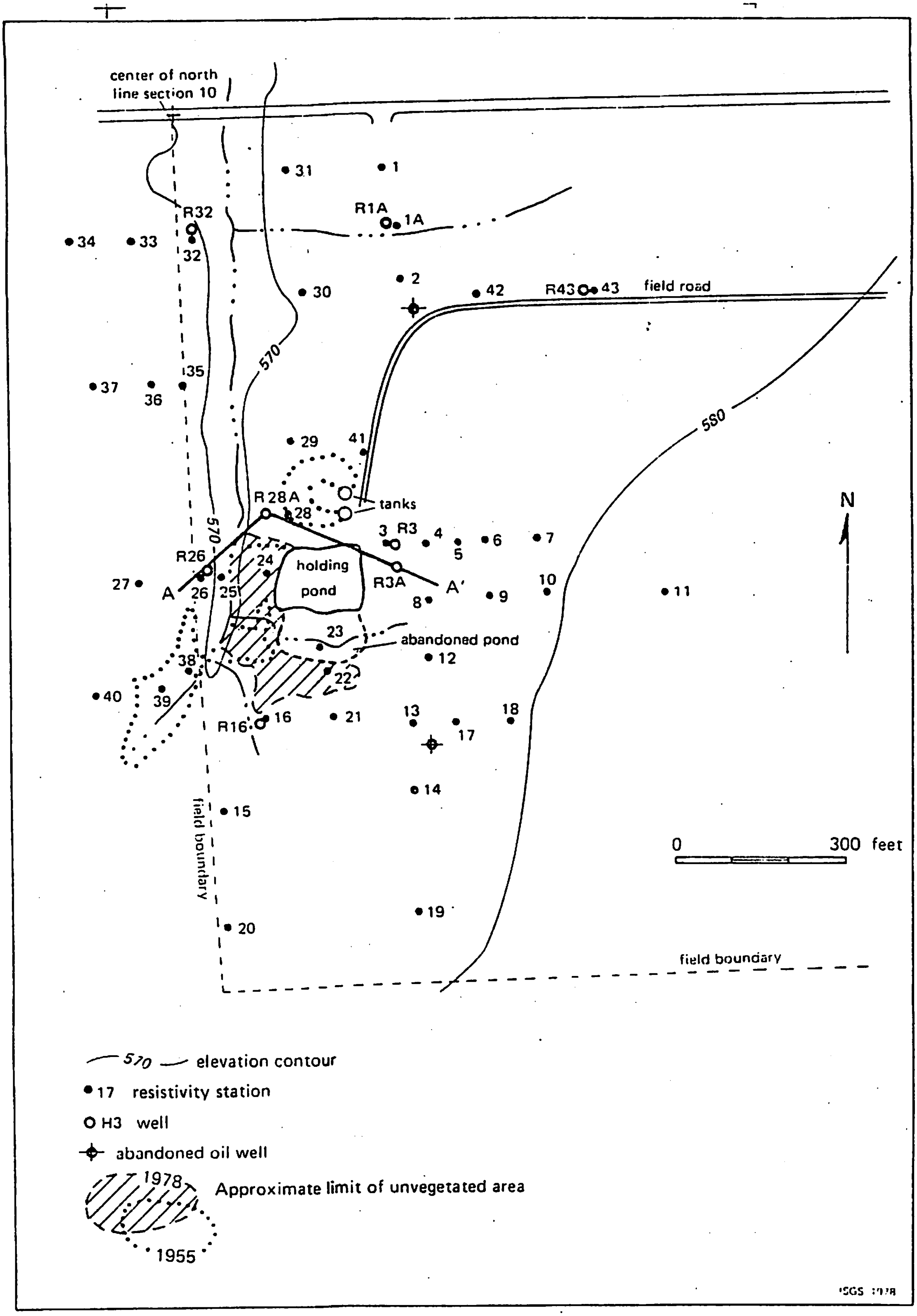
The generally higher apparent resistivity values from split spoon samples below the Hagarstown indicate that for the most part, the highly mineralized holding pond water has not migrated downward into the underlying till.

BOND COUNTY

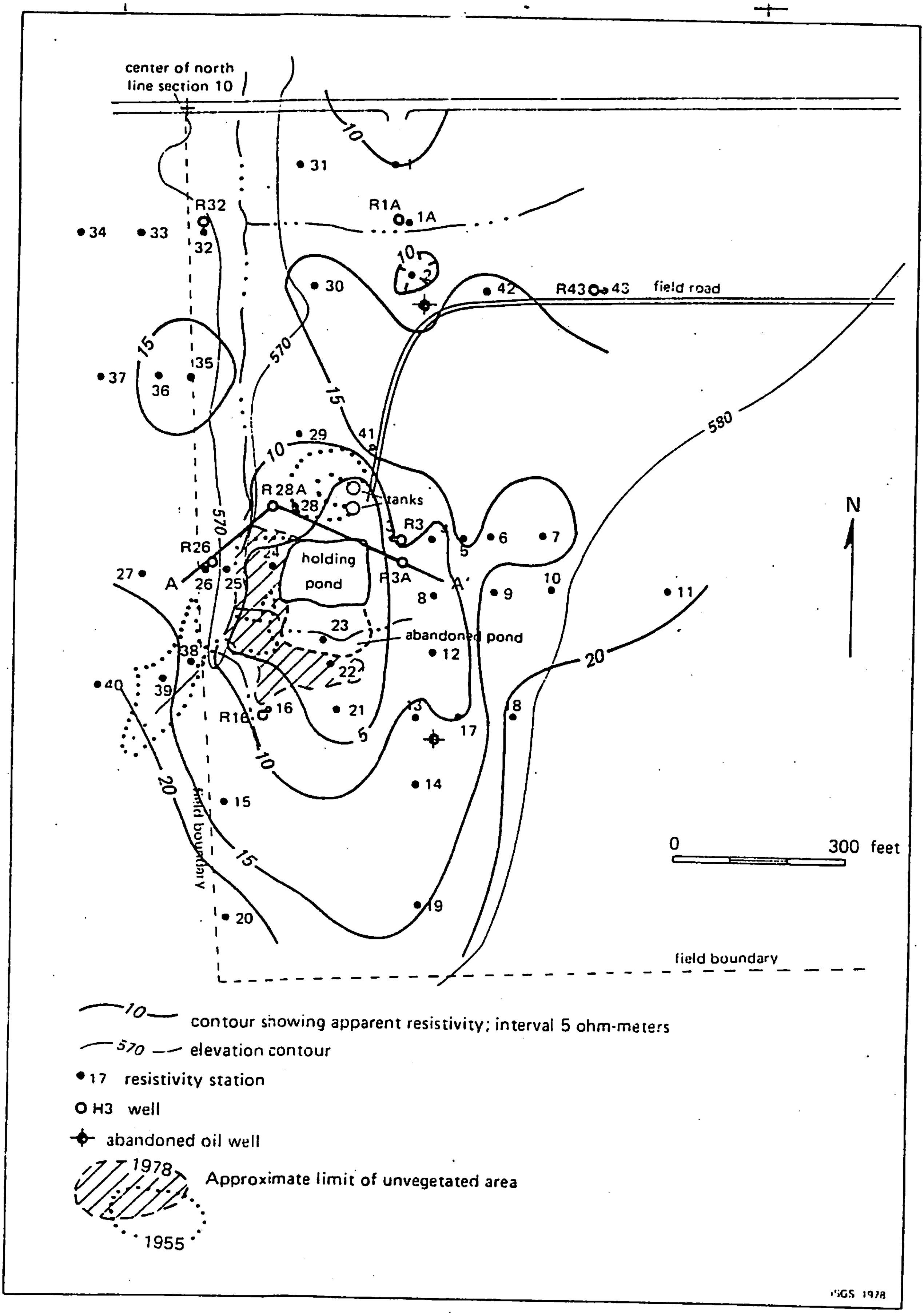
Well No.	Slot Interval	Relative Height Casing	Static Level Below Top Of Casing, July 20, 1978	Height Casing Above Ground	Relative Ground Level At Well	Static Level Below Ground	Ground Level Relative To Datum	Water Levels Relative To Ground Level Datum
R-1A	9-19	-	2.47	0.27	13.12	2.20	-5.92	+(-2.20)=-8.12
R-3	14-19	-	2.90	0.0	7.20	2.90	0.0	+(-2.90)=-2.90
R-3A	4-9	-	2.74	0.42	7.30	2.74	-0.10	+(-2.74)=-2.84
R-16	9-24	-	4.52	0.46	9.86	4.52	-2.66	+(-4.52)=-8.18
R-26	9-24	-	9.13	0.65	8.15	9.13	-0.95	+(-9.13)=-10.08
R-28A	14-19	-	3.39	0.20	12.70	3.39	-5.50	+(-3.39)=-8.89
R-32	9.24	-	7.57	0.15	10.76	7.57	-3.56	+(-7.57)=-11.13
R-43	9-24	-	3.27	0.30	6.55	3.27	+0.65	+(-3.27)=-2.62
R oil test					7.58 (top casing)			-0.38
R pit					6.25 (top fluid)			+0.95
R stream					18.50 (base channel)			-11.30



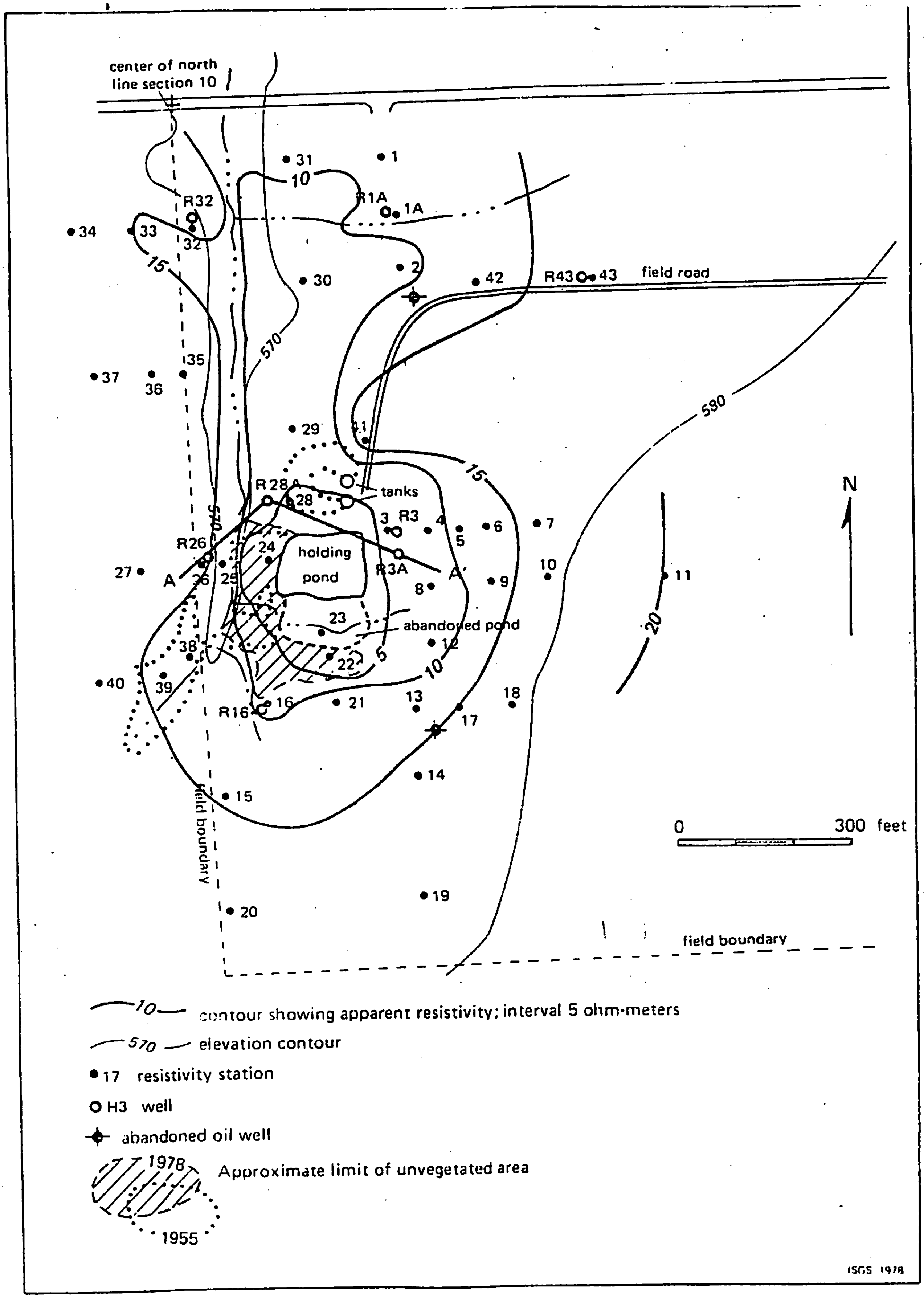
WATER LEVEL CONTOURS (DATUM GROUND LEVEL, WELL R-3)
AT THE WOBURN CONSOLIDATED OIL FIELD
Section 10, T. 6 N., R. 2 W., Bond County, Illinois
June 1978–Murphy, Osby (IEPA); Reed, Franczyk (ISGS)



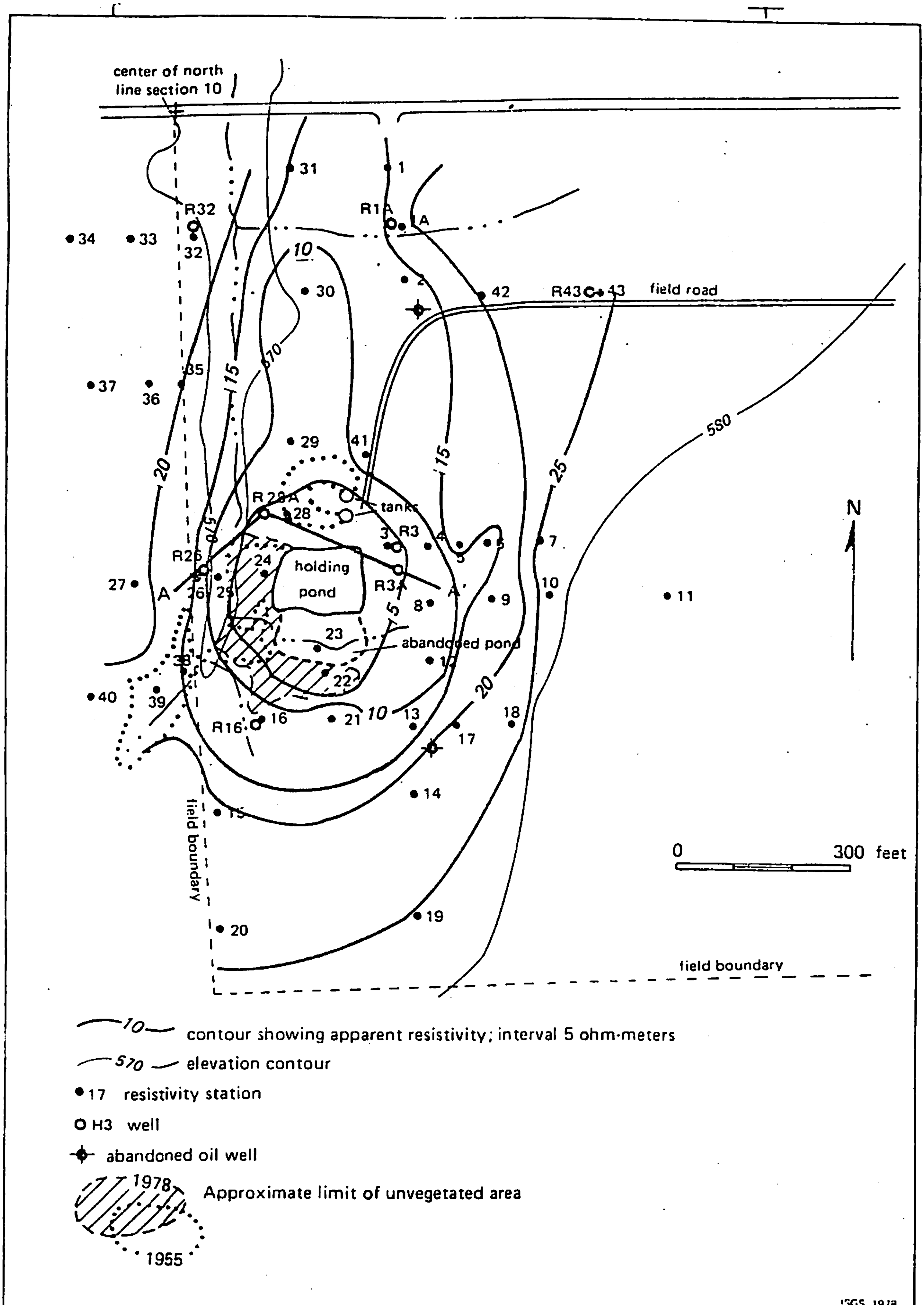
AN ELECTRICAL EARTH RESISTIVITY SURVEY
AT THE WOBURN CONSOLIDATED OIL FIELD
Section 10, T. 6 N., R. 2 W., Bond County, Illinois
June 1978—Murphy, Osby (IEPA); Reed, Franczyk (ISGS)



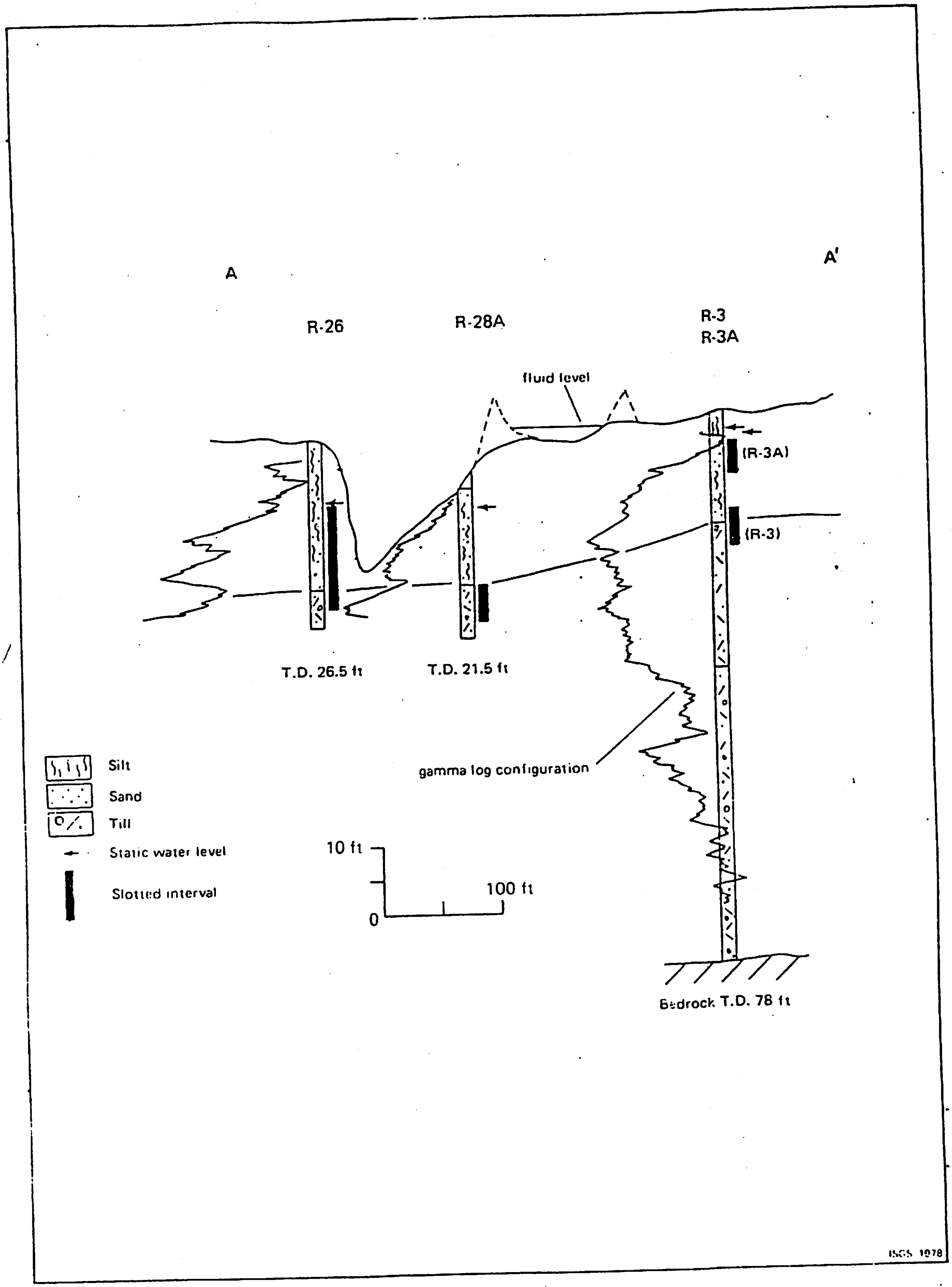
APPARENT RESISTIVITY (OHM-METERS) AT 5-FOOT DEPTH
AT THE WOBURN CONSOLIDATED OIL FIELD
Section 10, T. 6 N., R. 2 W., Bond County, Illinois
June 1978—Murphy, Osby (IEPA); Reed, Franczyk (ISGS)



APPARENT RESISTIVITY (OHM-METERS) AT 10-FOOT DEPTH
AT THE WOBURN CONSOLIDATED OIL FIELD
Section 10, T. 6 N., R. 2 W., Bond County, Illinois
June 1978—Murphy, Osby (IEPA); Reed, Franczyk (ISGS)



APPARENT RESISTIVITY (OHM-METERS) AT 20-FOOT DEPTH
AT THE WOBURN CONSOLIDATED OIL FIELD
Section 10, T. 6 N., R. 2 W., Bond County, Illinois
June 1978–Murphy, Osby (IEPA); Reed, Franczyk (ISGS)



GEOLOGIC SECTION AT THE WOBURN CONSOLIDATED OIL FIELD
Section 10, T. 6 N., R. 2 W., Bond County, Illinois
June 1978—Murphy, Osby (IEPA); Reed, Franczyk (ISGS)

APPENDIX E

Effingham-Fayette County
F.E.R. and Water Table Maps
Lithologic and Gamma Ray Logs

Effingham-Fayette Counties Holding Pond Study Site
Land Administrator: Mr. Dorwin Barr
Operator: Tri Star Oil Company
Pond Size: 110'x110'x6'
Present salt water input: 150-200 barrels daily (reported)

Geologic Setting

The Effingham-Fayette County study site is located in Section 31, T. 9 N., R. 4 W., within the Louden Oil Field. The land elevation ranges between 595-630 feet above mean sea level. Drainage is eastward and southward toward a tributary of Wolf Creek. The site is situated on the south flank of southwestward-northeastward trending series of elongate mounds which are elevated above the surrounding Illinoian till plain. The unconsolidated Illinoian glacial drift consists of sand, silt and till. The glacial drift is about 50 feet thick, and overlies the Mattoon Formation of Pennsylvanian age.

Hydrogeology

The surficial material consists of loessial silt which forms the soil in this area. In places near the abandoned ponds north, northeast, west and immediately south of the active pond a sandy, bleached spoil covering is present to a depth of 3 to 4 feet. Underlying the spoil and the soil is 5 to 18 feet of sand, silt and sandy till of the Hagarstown Member of the Glasford Formation. The Hagarstown is deeply weathered and has a uniform lithology in all parts of the study area except in the area of well no. G-49A where the sandy ablation till phase of the Hagarstown becomes dominant.

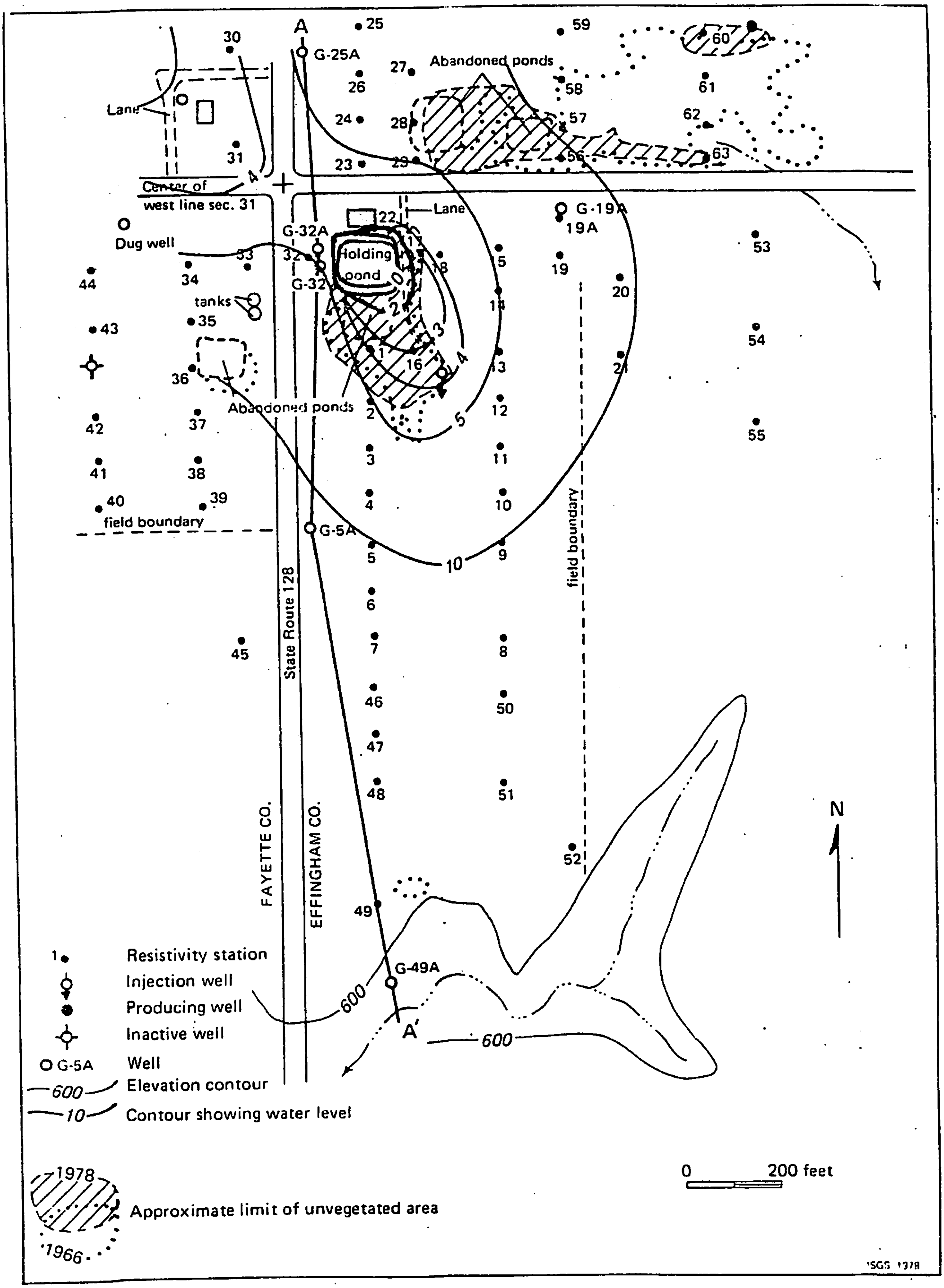
Beneath the Hagarstown is a tough sandy till, the Vandalia Member of the Glasford Formation. The Vandalia Member is greatly compacted in contrast to the overlying Hagarstown (see engineering data in appendix) which has comparatively greater permeability. The Vandalia appears fractured in some of the split spoon samples studied and therefore may be hydraulically connected to the overlying Hagarstown in places.

Hydrology

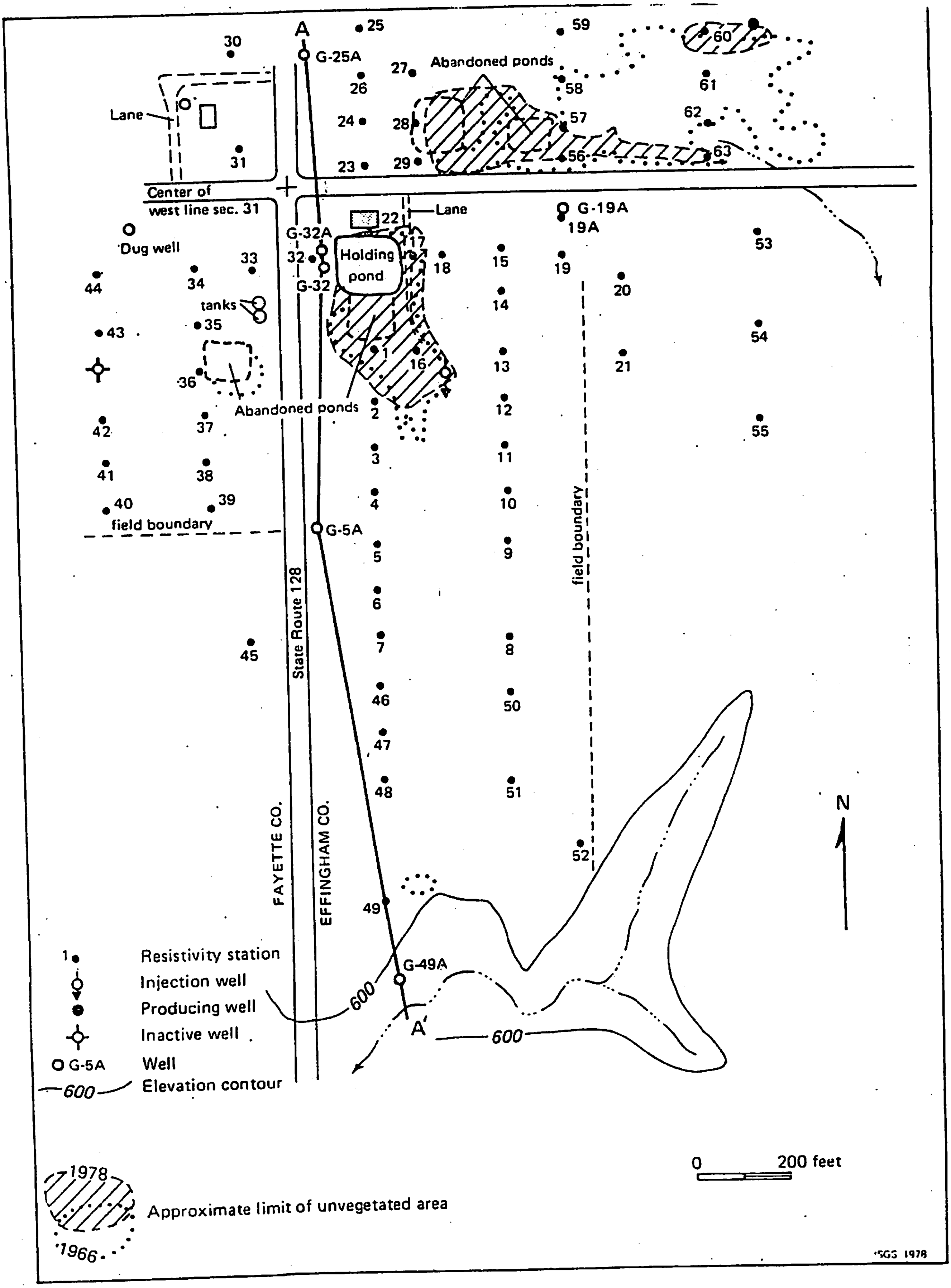
Water level contours around the holding pond indicate a ground-water mound beneath the pit with a gradient southward toward the creek. The distribution of apparent resistivity reflects the coalescing and interaction of the chloride migration from the active pond and the inactive holding ponds. The greatest migration of brine is southward toward the creek and west, northeast and east outward from the vicinity of the abandoned holding ponds. This relationship is shown on the apparent resistivity maps. The limit of the unvegetated area has decreased considerably in the locale of the abandoned holding ponds based on patterns shown on the 1966 aerial photograph.

E F F I N G H A M - F A Y E T T E   C O U N T I E S

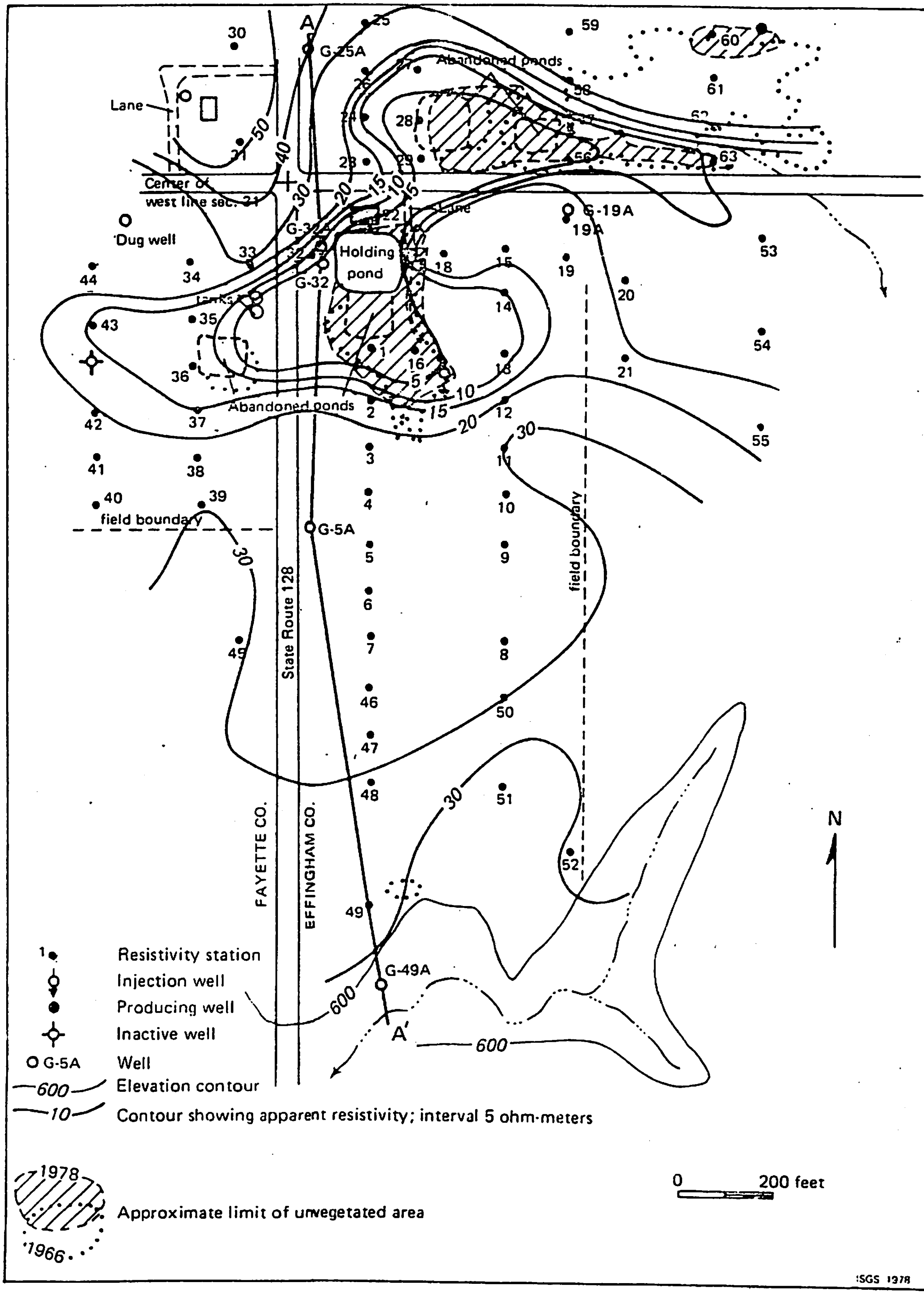
Well No.	Slot Interval	Relative Height Casing	Static Level Below Top Of Casing, July 20, 1978	Height Casing Above Ground	Relative Ground Level At Well	Static Level Below Ground	Ground Level Relative To Datum	Water Levels Relative To Ground Level Datum
G-Huffman		-	8.15	0.0	3.3	8.15	+5.02	+(-8.15)=-3.13
G-5A	4-14	-	5.45	0.3	13.91	5.15	-5.59	+(-5.15)=-10.74
G-19A	4-14	-	6.80	2.45	12.95	4.35	-4.63	+(-4.35)=-8.89
G-25A	9-14	-	5.20	0.60	4.85	4.60	+3.47	+(-4.60)=-1.13
G-32	4-14	-	8.05	2.90	8.32	5.15	0.0	+(-5.15)=-5.15
G-32A	14-17	-	7.45	2.55	8.30	4.90	+0.02	+(-4.90)=-4.88
G-49A	4-9	-	No Water	0.45	23.64	-	-15.32	
Creek					46.26 base channel		-37.94	
Pit		MP 7.18	1.8		8.98 (top fluid)		-0.66	-0.66



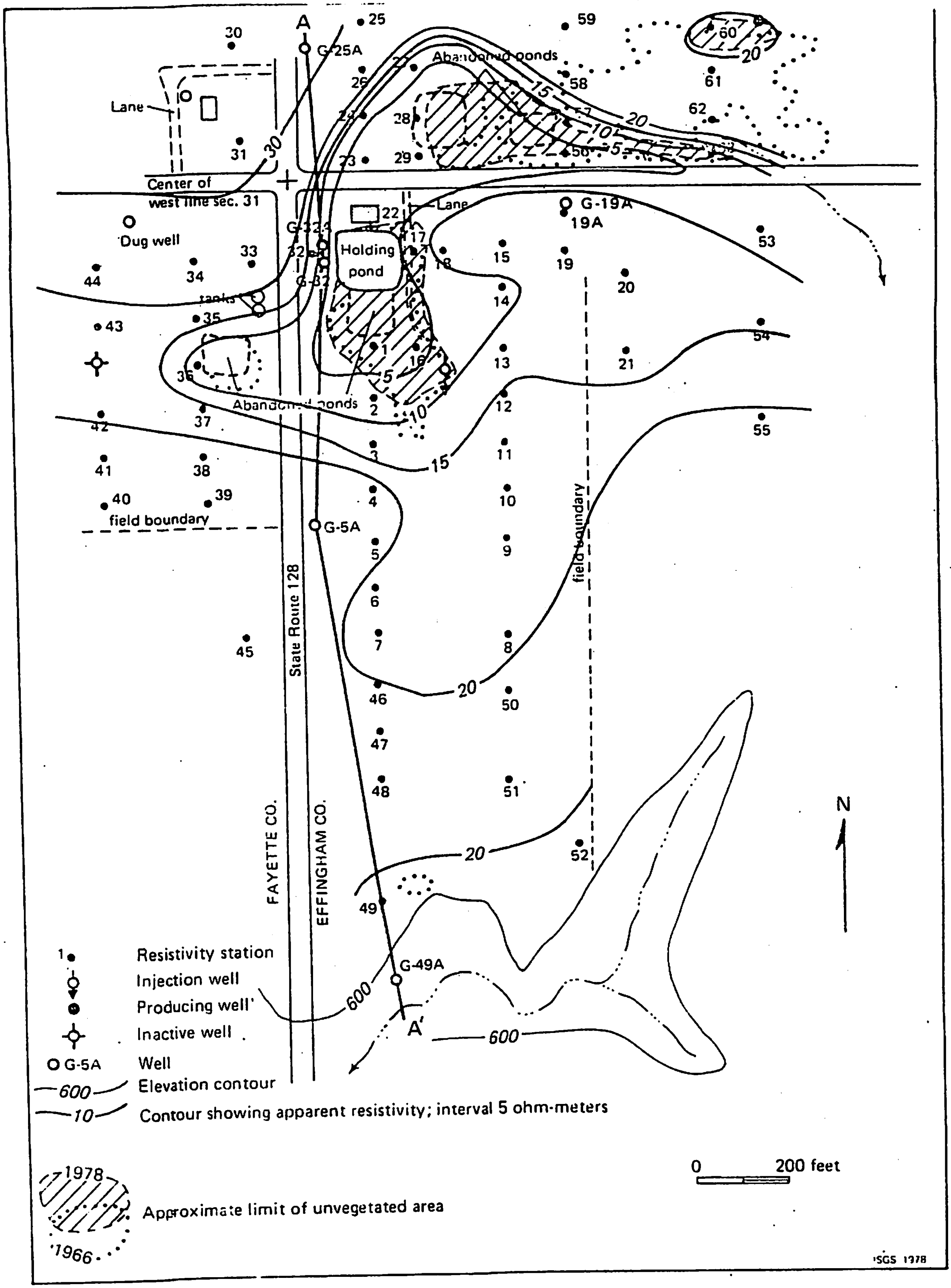
WATER LEVEL CONTOURS (DATUM GROUND LEVEL, G-32)
AT THE LOUDEN POOL OIL FIELD
Section 31, T. 9 N., R. 4 E., Effingham County, Illinois,
and Section 36, T. 9 N., R. 3 E., Fayette County, Illinois
July 1978—Murphy, Osby (IEPA); Reed (ISGS)



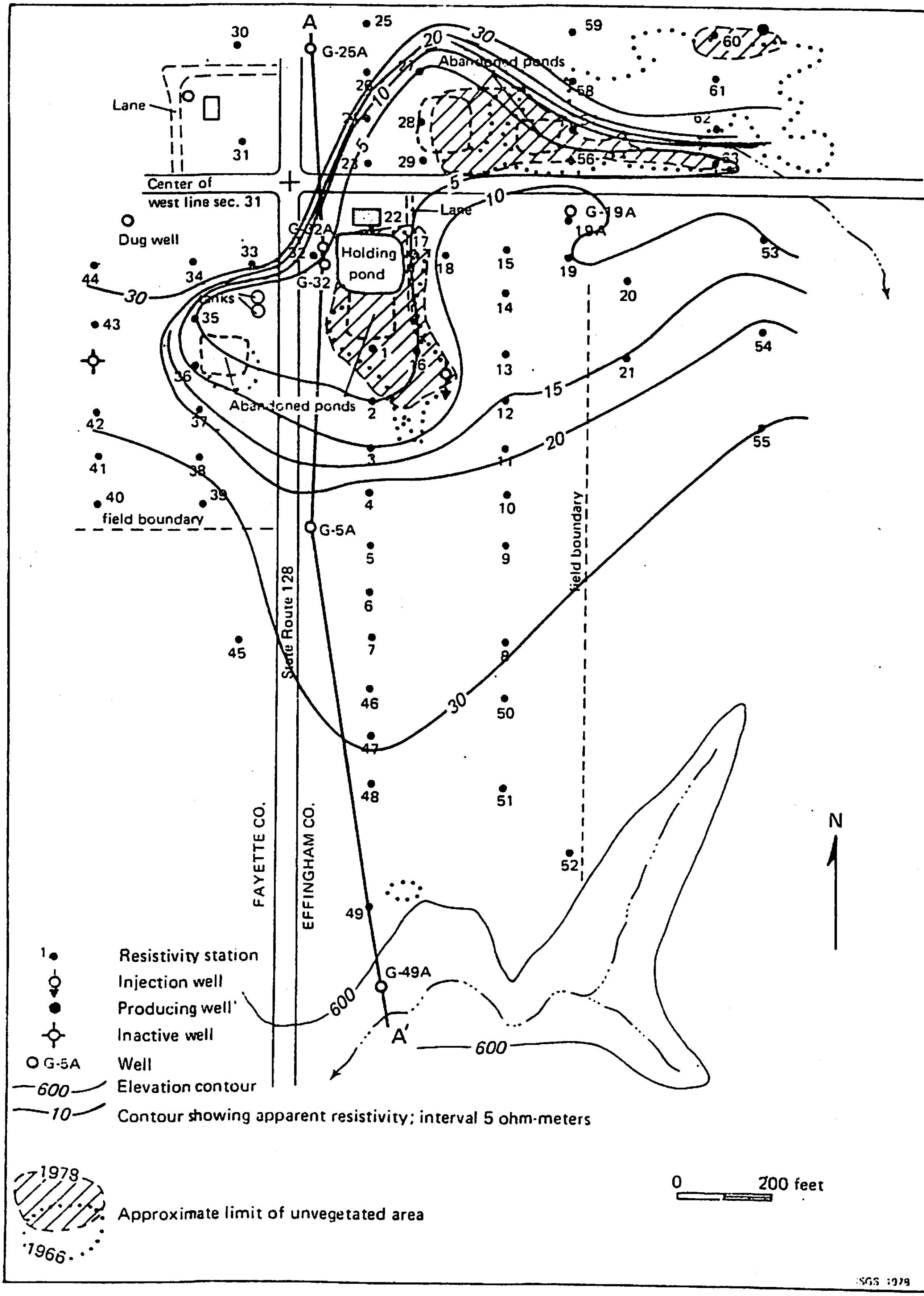
AN ELECTRICAL EARTH RESISTIVITY SURVEY
AT THE LOUDEN POOL OIL FIELD
Section 31, T. 9 N., R. 4 E., Effingham County, Illinois
and Section 36, T. 9 N., R. 3 E., Fayette County, Illinois
July 1978—Murphy, Osby (IEPA); Reed (ISGS)



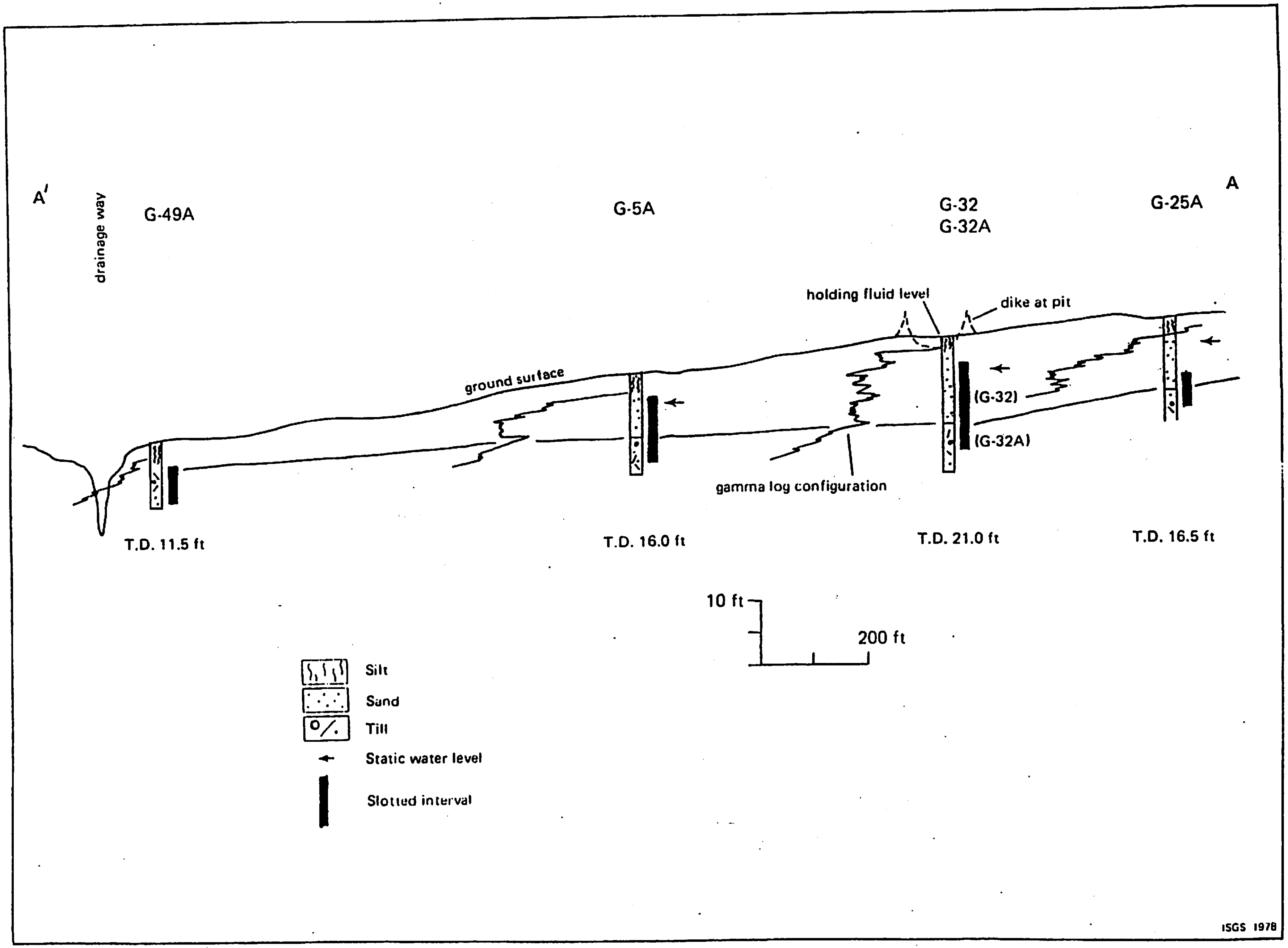
APPARENT RESISTIVITY (OHM-METERS) AT 5-FOOT DEPTH
AT THE LOUDEN POOL OIL FIELD
Section 31, T. 9 N., R. 4 E., Effingham County, Illinois
and Section 36, T. 9 N., R. 3 E., Fayette County, Illinois
July 1978–Murphy, Osby (IEPA); Reed (ISGS)



APPARENT RESISTIVITY (OHM-METERS) AT 10-FOOT DEPTH
AT THE LOUDEN POOL OIL FIELD
Section 31, T. 9 N., R. 4 E., Effingham County, Illinois
and Section 36, T. 9 N., R. 3 E., Fayette County, Illinois
July 1978–Murphy, Osby (IEPA); Reed (ISGS)



APPARENT RESISTIVITY (OHM-METERS) AT 20-FOOT DEPTH
AT THE LOUDEN POOL OIL FIELD
Section 31, T. 9 N., R. 4 E., Effingham County, Illinois
and Section 36, T. 9 N., R. 3 E., Fayette County, Illinois
July 1978—Murphy, Osby (IEPA); Reed (ISGS)



GEOLOGIC SECTION AT THE LOUDEN POOL OIL FIELD
Section 31, T. 9 N., R. 4 E., Effingham County, Illinois,
and Section 36, T. 9 N., R. 3 E., Fayette County, Illinois
July

APPENDIX F

Clay County
E.E.R. and Water Table Maps
Lithologic and Gamma Ray Logs

Clay County Holding Pond Study Site
Land Administrator: Mr. Albert Hayes
Operator: Shelby A. Britton
Pond Size: 150'x60'x6'. Date Constructed: 1950?
Present salt water input: 4 barrels daily (reported)

Geologic Setting

The Clay County study site is located in Sections 21 and 28, T. 3 N., R. 7 E., within the Sailor Springs Consolidated Oil Field. The land elevation ranges between 445-455 feet above mean sea level. Drainage is westward toward a tributary of Elm River. The unconsolidated Illinoian glacial drift and loess which consists of silt, sand and glacial till is about 25 feet thick and overlie the Mattoon Formation of Pennsylvanian age.

Hydrogeology

The site is overlain to the west and north with 0-3 feet of loose, often moist, fairly clean sand with granules, probably spoil derived from the pond excavation. This surficial material is porous and permeable and appears to transmit pond fluid readily. Beneath this spoil and in areas where the spoil is not present is about 10-15 feet of loosely compacted soil, sand, silt and deeply weathered till of the Hagarstown Member of the Glasford Formation. Underlying the Hagarstown is ten or more feet of tough dry compacted (see unconfined compressive strength measurements) relatively impermeable till which is believed to lie on bedrock.

Hydrology

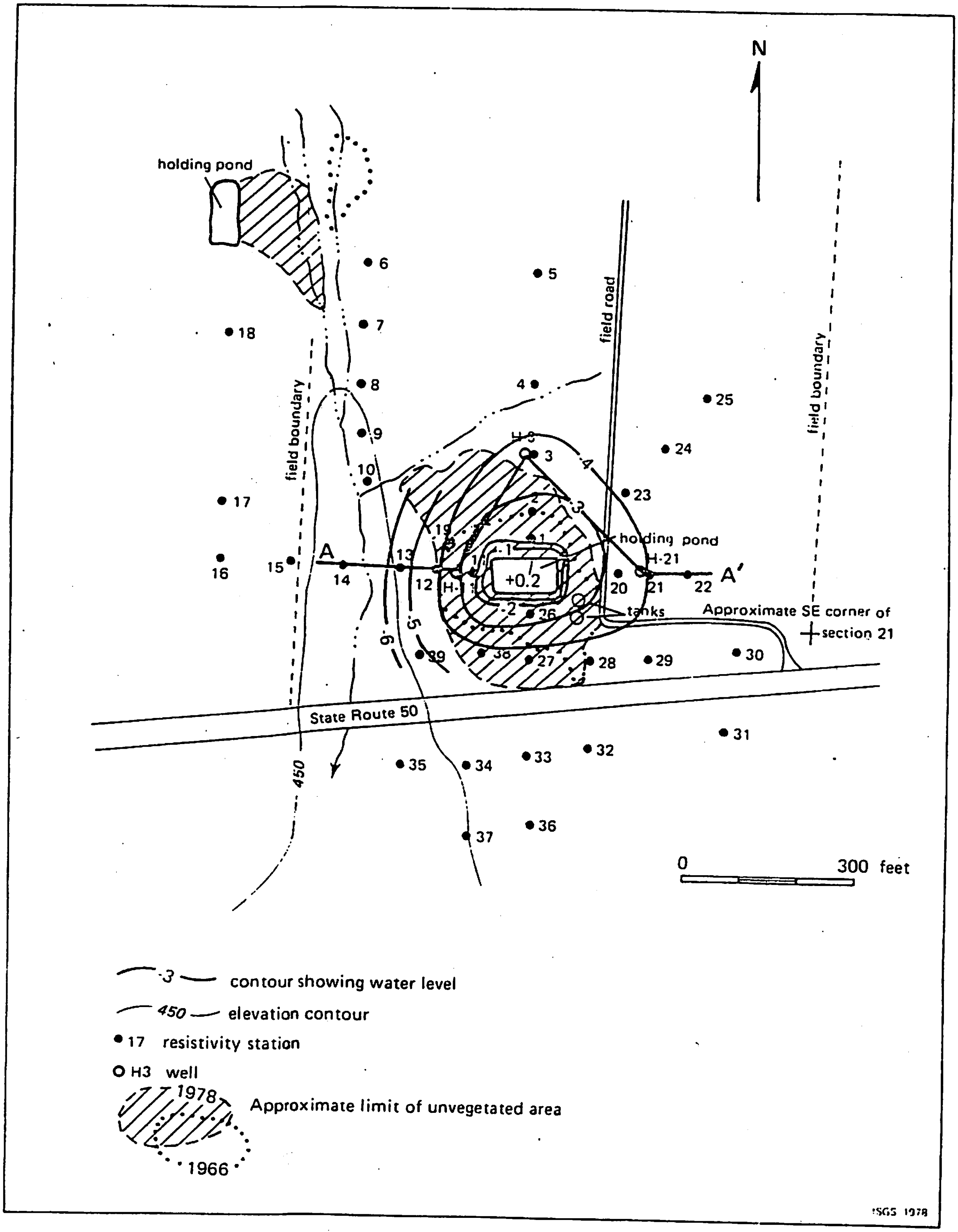
Water level contours around the holding pond indicate a ground-water mound beneath the pond with a general gradient westward toward the creek.

The distribution of the isoresistivity contours indicate that the greatest migration of chlorides is toward the southeast and northwest. The construction of state route 50 in the early 1970's appears to have interrupted

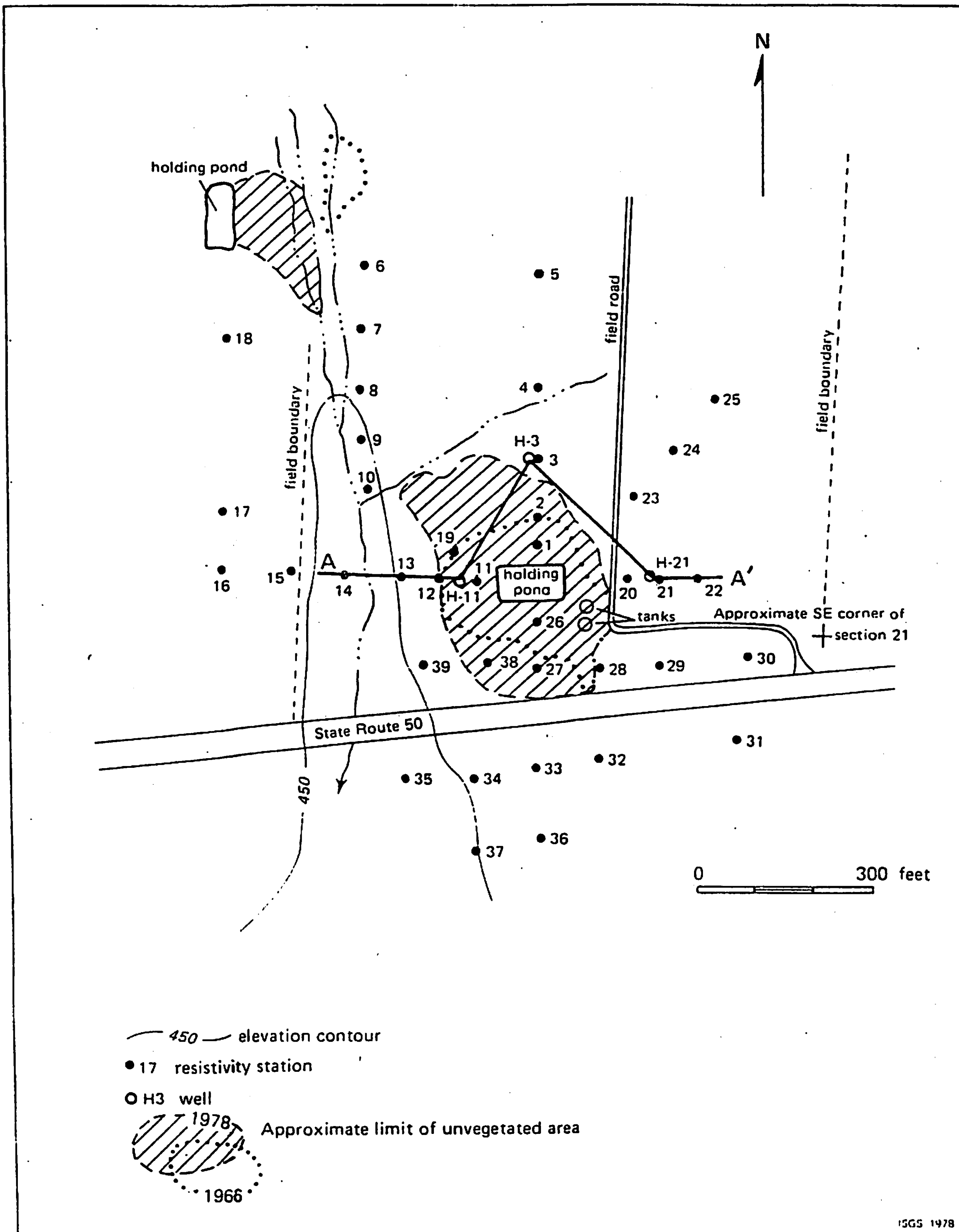
a part of the southeastward migration of the unvegetative area around the pit. To the northwest, since 1966, the unvegetated area has extended outward 200 feet to a field waterway coincident with the chloride migration (note photographs).

C L A Y   C O U N T Y

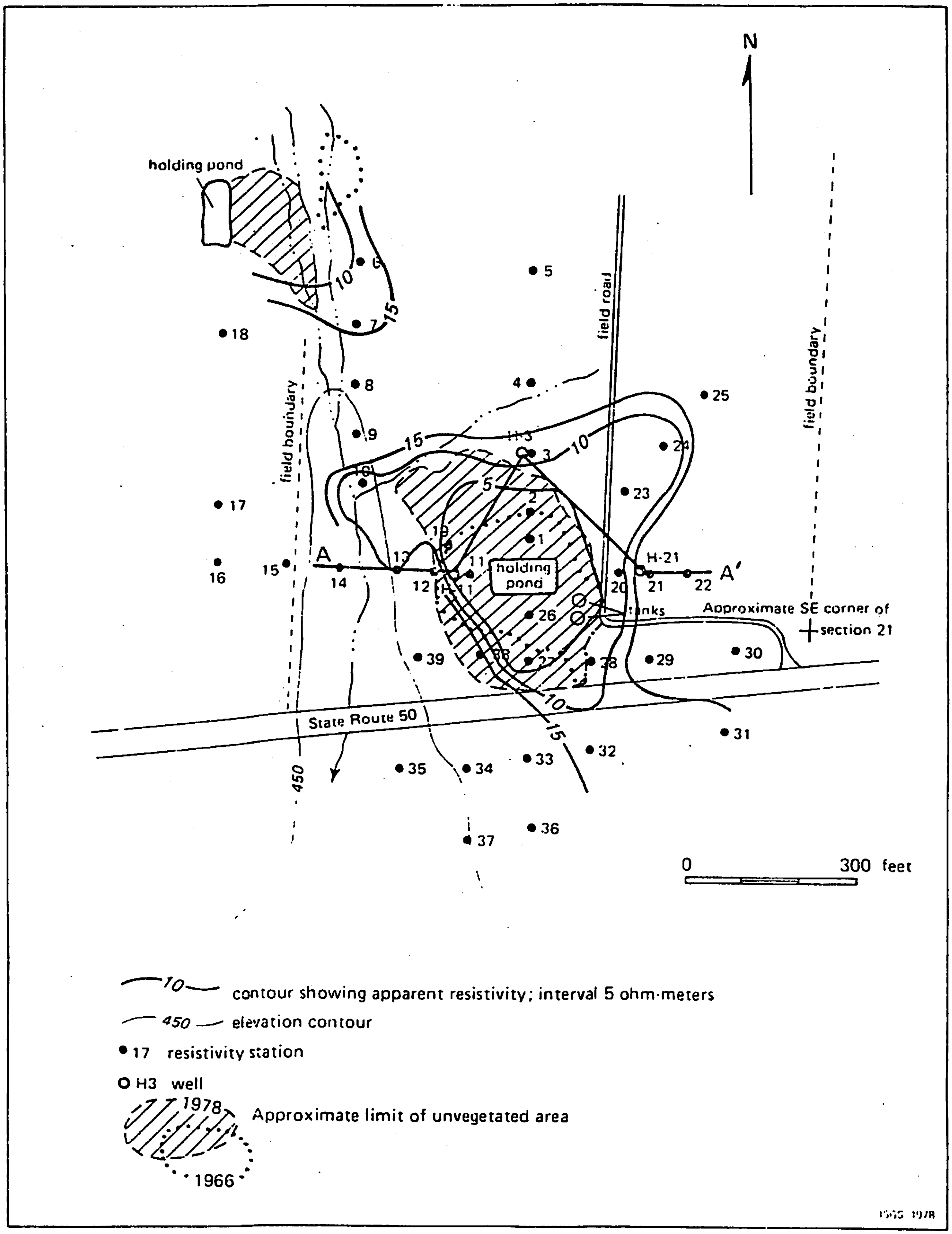
Well No.	Slot Interval	Relative Height Casing	Static Level Below Top Of Casing, July 20, 1978	Height Casing Above Ground	Relative Ground Level At Well	Static Level Below Ground	Ground Level Relative To Datum	Water Levels Relative To Ground Level Datum
H-3	4-14	5.00	3,65	0.3	4,70	3,35	+0,15	+(-3,35)=-2,20
H-11	4-14	4,85	3.90	0,0	4,85	3,90	0,0	+(-3,90)=-3,90
H-21	4-14	5.10	4,20	0,35	4,75	3,85	-0,05	+(-3.85)=-3.90
H-21	21-24	4.90	21.35	0.15	4.65	21.20	+0.20	+(-21.20)=-21.00



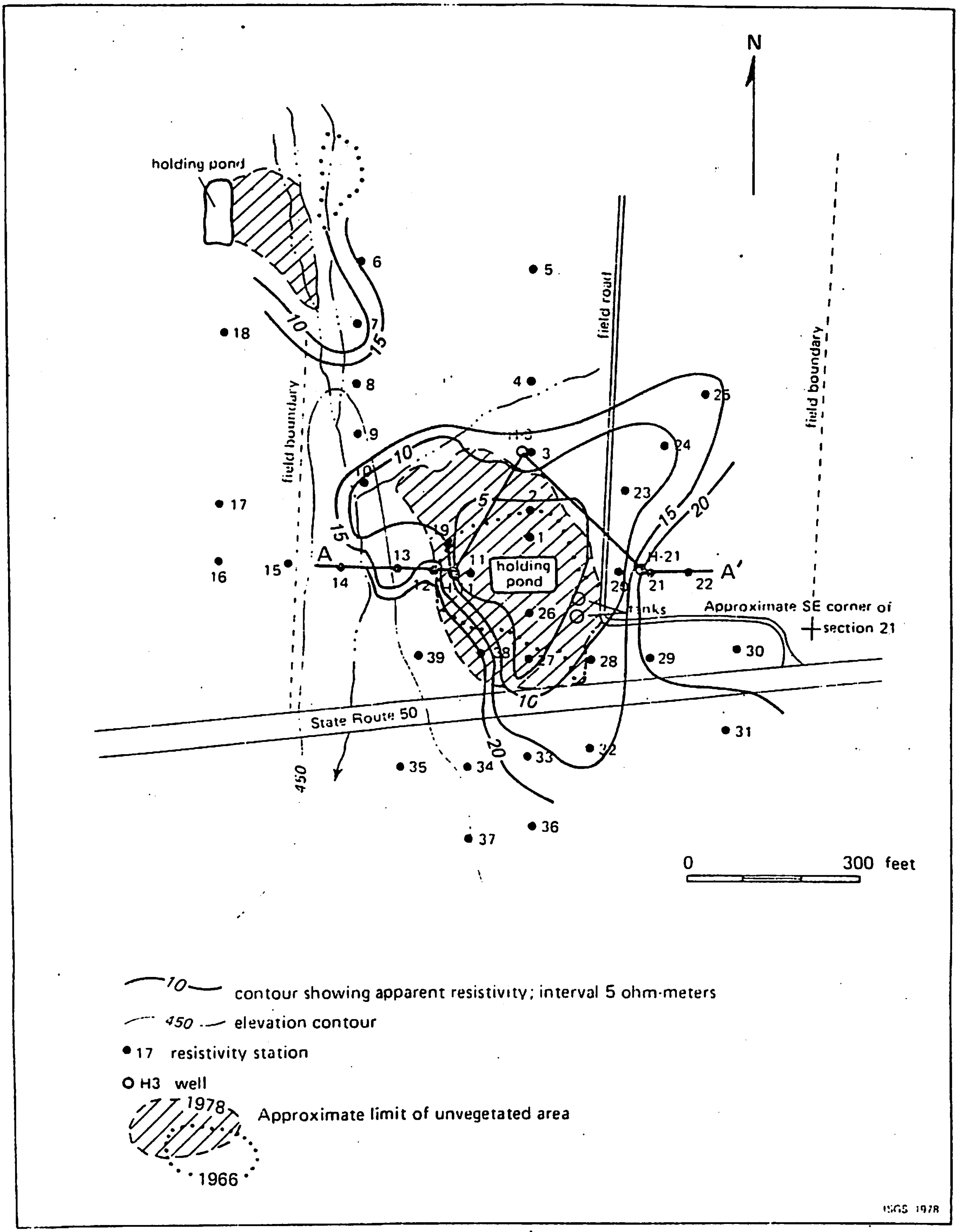
POTENTIOMETRIC SURFACE (DATUM GROUND LEVEL, WELL H-11)
SAILOR SPRINGS CONSOLIDATED OIL FIELD
Section 21, T. 3 N., R. 7 E., Clay County, Illinois
July 1978—Murphy, Osby (IEPA); Reed (ISGS)



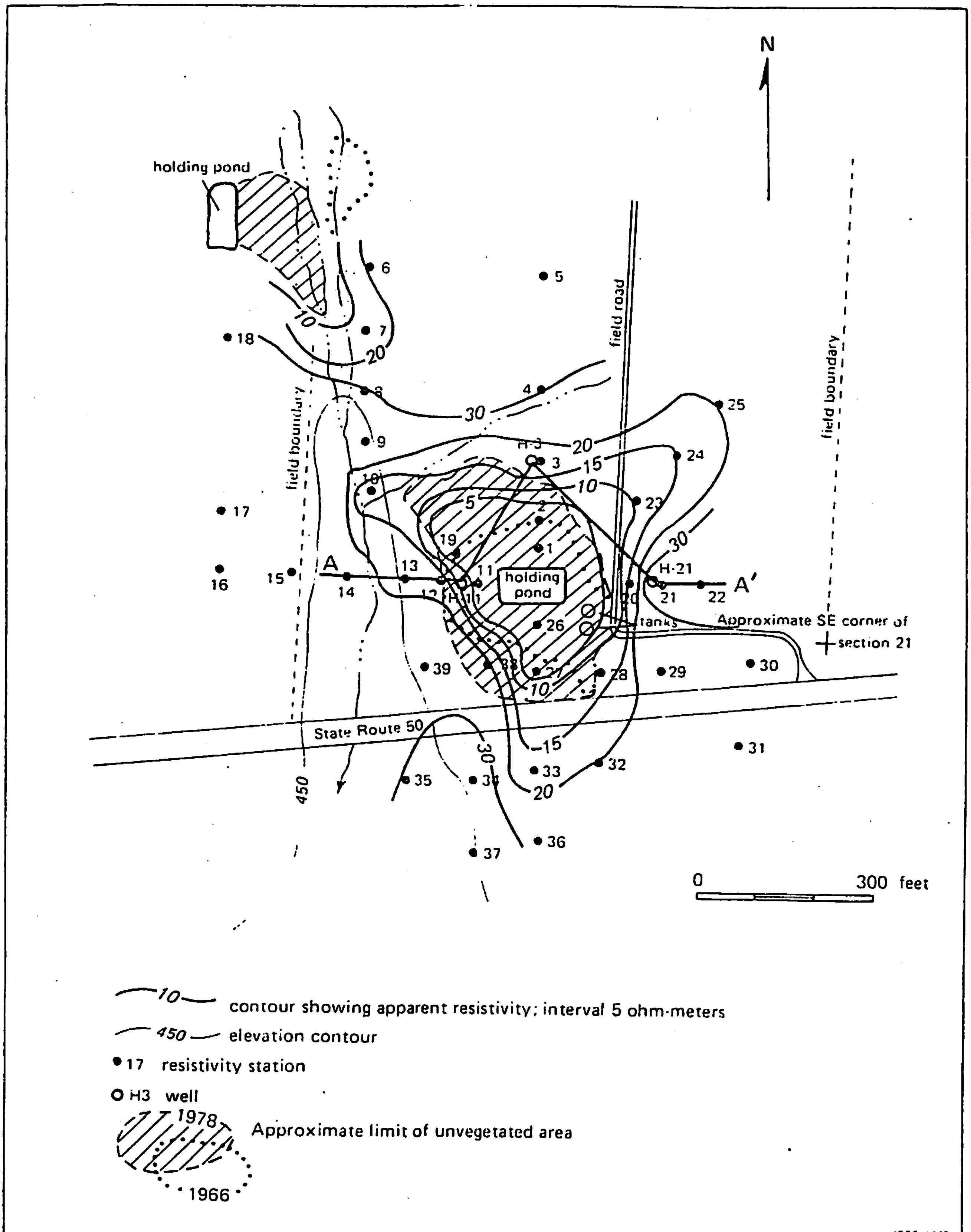
AN ELECTRICAL EARTH RESISTIVITY SURVEY
AT THE SAILOR SPRINGS CONSOLIDATED OIL FIELD
Sections 21 and 28, T. 3 N., R. 7 E., Clay County, Illinois
July 1978–Murphy, Osby (IEPA); Reed (ISGS)



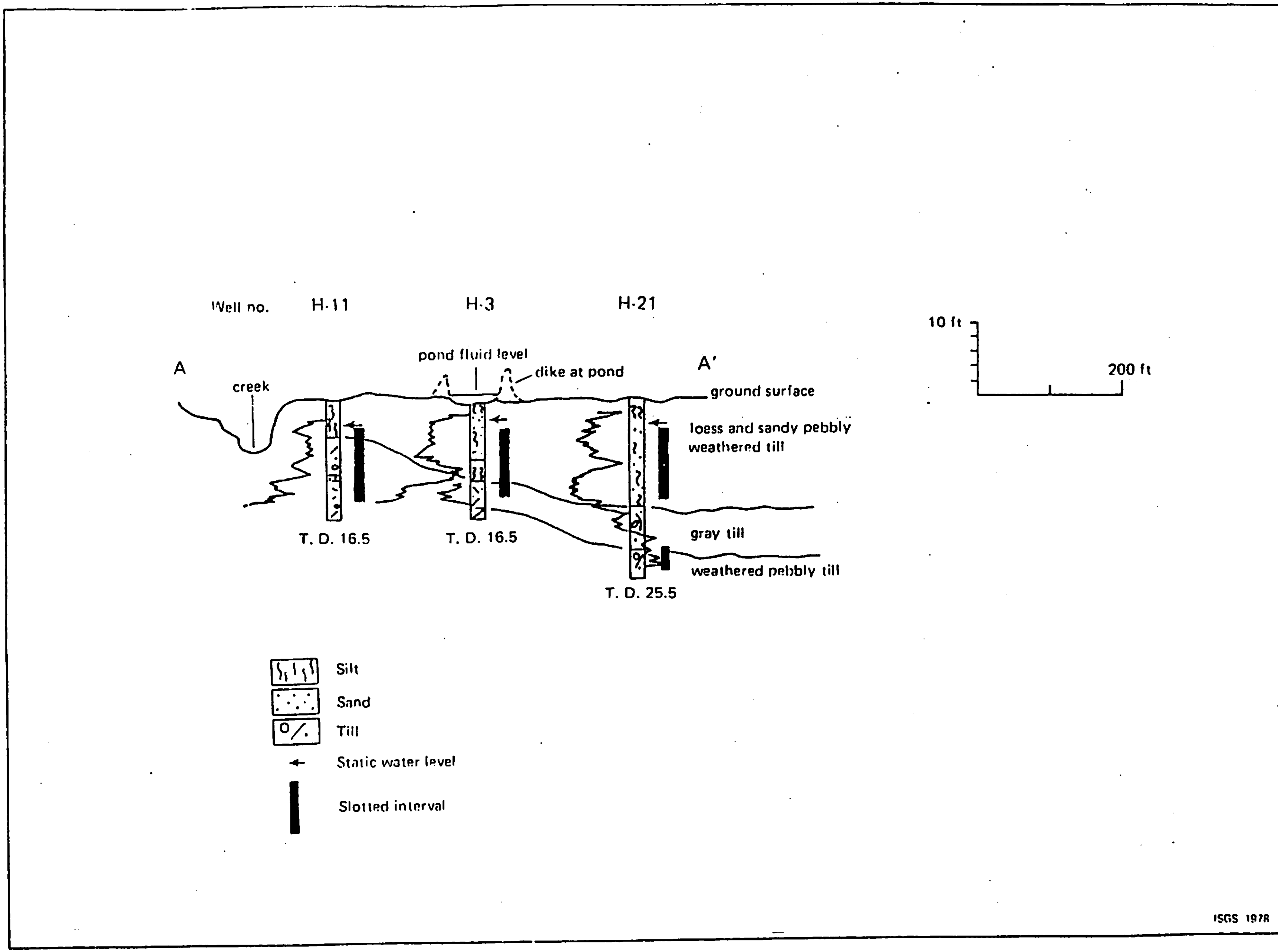
APPARENT RESISTIVITY (OHM-METERS) AT 5-FOOT DEPTH
AT THE SAILOR SPRINGS CONSOLIDATED OIL FIELD
Sections 21 and 28, T. 3 N., R. 7 E., Clay County, Illinois
July 1978—Murphy, Osby (IEPA); Reed (ISGS)



APPARENT RESISTIVITY (OHM-METERS) AT 10-FOOT DEPTH
AT THE SAILOR SPRINGS CONSOLIDATED OIL FIELD
Sections 21 and 28, T. 3 N., R. 7 E., Clay County, Illinois
July 1978–Murphy, Osby (IEPA); Reed (ISGS)



APPARENT RESISTIVITY (OHM-METERS) AT 20-FOOT DEPTH
AT THE SAILOR SPRINGS CONSOLIDATED OIL FIELD
Sections 21 and 28, T. 3 N., R. 7 E., Clay County, Illinois
July 1978—Murphy, Osby (IEPA); Reed (ISGS)



GEOLOGIC CROSS SECTION A-A'
SAILOR SPRINGS CONSOLIDATED OIL FIELD
Section 21, T. 3 N., R. 7 E., Clay County, Illinois
July 1978–Murphy, Osby (IEPA); Reed (ISGS)

New York State
Oil, Gas
and
Mineral Resources
2008

New York State
Department of Environmental Conservation
Division of Mineral Resources
625 Broadway
Albany, New York 12233-6500

www.dec.ny.gov

Division Mission Statement

The Division of Mineral Resources is responsible for ensuring the environmentally sound, economic development of New York's non-renewable energy and mineral resources for the benefit of current and future generations.

This report was produced by the
NYS Department of Environmental Conservation

Division of Mineral Resources
625 Broadway
Albany, NY 12233-6500
(518) 402-8076

Bradley J. Field, Director

Executive Summary

Mining occurs in every region of the State except the New York City area. Oil and gas development has historically occurred in the western half of the State, but the Finger Lakes region has been experiencing heavy activity for several years. Because of differences in legal reporting requirements, the types of statistics presented for the two programs are not identical.

Oil, Gas and Solution Mining

Inspections - Staff traveled 95,672 miles and performed 2,445 oil and gas inspections.

Permits and Completions

Gas:	Permits	429	Completions	270
Oil:	Permits	250	Completions	172
Other:	Permits	58	Completions	58
Total:	Permits	737	Completions	500

Wells Reported (All Types) 2008 - 14,513

Wells To Date (All Types) - 75,000; majority pre-regulation (most plugging status unknown).

Production and Market Value

Gas	50.320 bcf	Value Down	7%
Oil	397,060 bbl	Value Up	25%
Total O&G Mkt Value	$488 million		

State Leasing - 91 leases were in effect covering 63,591 acres; 266 producing wells.

Revenues from Oil and Gas

State Revenues	$3.1 million
Local Govt. Taxes (est.)	$14.6 million
Landowner Royalties (est.)	$61.0 million

Underground Natural Gas Storage - 24 facilities were 79% full at year-end.

Total Storage Capacity	223 bcf
Working Gas Capacity	113 bcf
Max. Deliverability	2.127 bcf/day

Solution Mining - Five facilities produced 1.93 billion gallons of brine, equal to 2.25 million metric tons of salt.

Financial Security - In 2008 New York held $24.7 million to guarantee well plugging and site reclamation.

Mined Land Reclamation

Inspections - Staff traveled 89,964 miles to perform 2,417 mine inspections.

Permits Issued		**Annual Fees**
Total Permits	462	$2.8 Million
New Permits	37	
Renewal & Mod.	585	

Active Mines 2,166

Estimated Market Value $1.3 billion

US Production Rank by Quantity

Wollastonite	1st	Salt, Peat	3rd
Garnet	1st	Talc, Zinc	4th

NY Rank by Value

Crushed Stone	1st	Sand & Gravel	4th
Cement	2nd	Zinc	5th
Salt	3rd	Wollastonite	6th

Common Mine Types

Sand & Gravel	1,734
Limestone	80
Bluestone	83

Owner Type

Industry	1,708
County	49
Town	395

Net Affected Acreage	49,076
Life-of-Mine Acreage	119,183
Reclaimed Acreage, 2008	1,842
Reclaimed Since 1975	28,520

Financial Security - In 2008 New York required $167.5 million to guarantee mine site reclamation.

Division of Mineral Resources Program Highlights

New York State gas production in 2008 was 50.320 billion cubic feet (bcf), down 8.4% from the previous year. Trenton-Black River production declined, but still accounted for 69% (34.8 bcf) of 2008 production. Oil production rose 3% to 397,060 barrels in 2008.

The total number of wells completed dropped 6% from 2008, but the number of gas wells completed (270) remained almost exactly the same as the previous year. Four new Trenton-Black River gas fields started production in 2008: Dry Run Creek and Lamoka in Steuben County, Skye-Top in Chemung County, and Halsey Valley in Tioga County.

In 2008 drilling permits rose 28% to 737, which is close to permit levels in 1983-1984, another period of high activity. Total drilled depth of the wells for the year was over 1.37 million feet (more than the distance from Schenectady to Buffalo). Drilling rig availability continued to be a significant concern for New York's oil and gas operators.

By year-end 2008 a total of 19 deep wells had been drilled on or adjacent to State land. In 2008 New York collected $2.0 million in royalties from the wells draining State land. Steuben County had the most State acreage under lease.

In 2008 the Division of Mineral Resources conducted 42 compulsory integration hearings, which resulted in 36 finalized orders. The remaining orders were referred to the Office of Hearings and Mediation Services for adjudication on issues including data and site access, assessment of risk penalties, and pipeline costs.

Marcellus permit activity increased greatly in 2008. The Division received a total of 58 Marcellus permit applications (45 vertical, 13 horizontal). Six vertical Marcellus wells were spud in 2008 in Allegany, Chemung and Chenango counties. The 2008 activity brought the State's total number of Marcellus producing wells to 15.

In 2008 there were 2,166 active DEC-regulated mines in New York State, a drop of 27 mines from 2007 and the tenth straight year of decline. Increasingly, mine operators are choosing to replace production by expanding current mines, rather than opening new ones. This trend holds true for both sand and gravel mines and hardrock quarries. Only 37 of the 462 mining permits issued in 2008 were for new facilities.

Nevertheless, production of the State's major mined commodities remains relatively level from year to year. The U.S. Geological Survey estimates the annual value of New York's mineral production at roughly $1.3 billion. Mining is spread fairly evenly across the State because of the need to keep trucking distances down and reduce the cost of transporting heavy materials. Sand and gravel mines account for over 80% of DEC-regulated mines and 29 of the new permits issued in 2008, or 78%, were for sand and gravel.

Interest in bluestone mining remained steady in 2008. One new mine was permitted and seven Exploration Authorizations were issued to mine operators allowing them to evaluate potential bluestone sites for a limited period of time (one year with possible one-year renewal).

A total of 49,076 acres were affected by mining in 2008 out of a total approved life-of-mine area of 119,183 acres. The Division continued to have success promoting concurrent reclamation with 1,205 acres reclaimed at 97 operating mines. Final reclamation of 637 acres occurred at 74 closed mines bringing the 2008 total to 1,842 acres. Roughly 28,520 acres of land affected by mining have been reclaimed since 1975.

In 2008 the Division held over $167.5 million in financial security to guarantee mine reclamation. The increase of $28 million from the previous year was due, in part, to a new method for calculating financial security introduced in 2006. The improved method brings financial security requirements more in line with modern-day reclamation costs.

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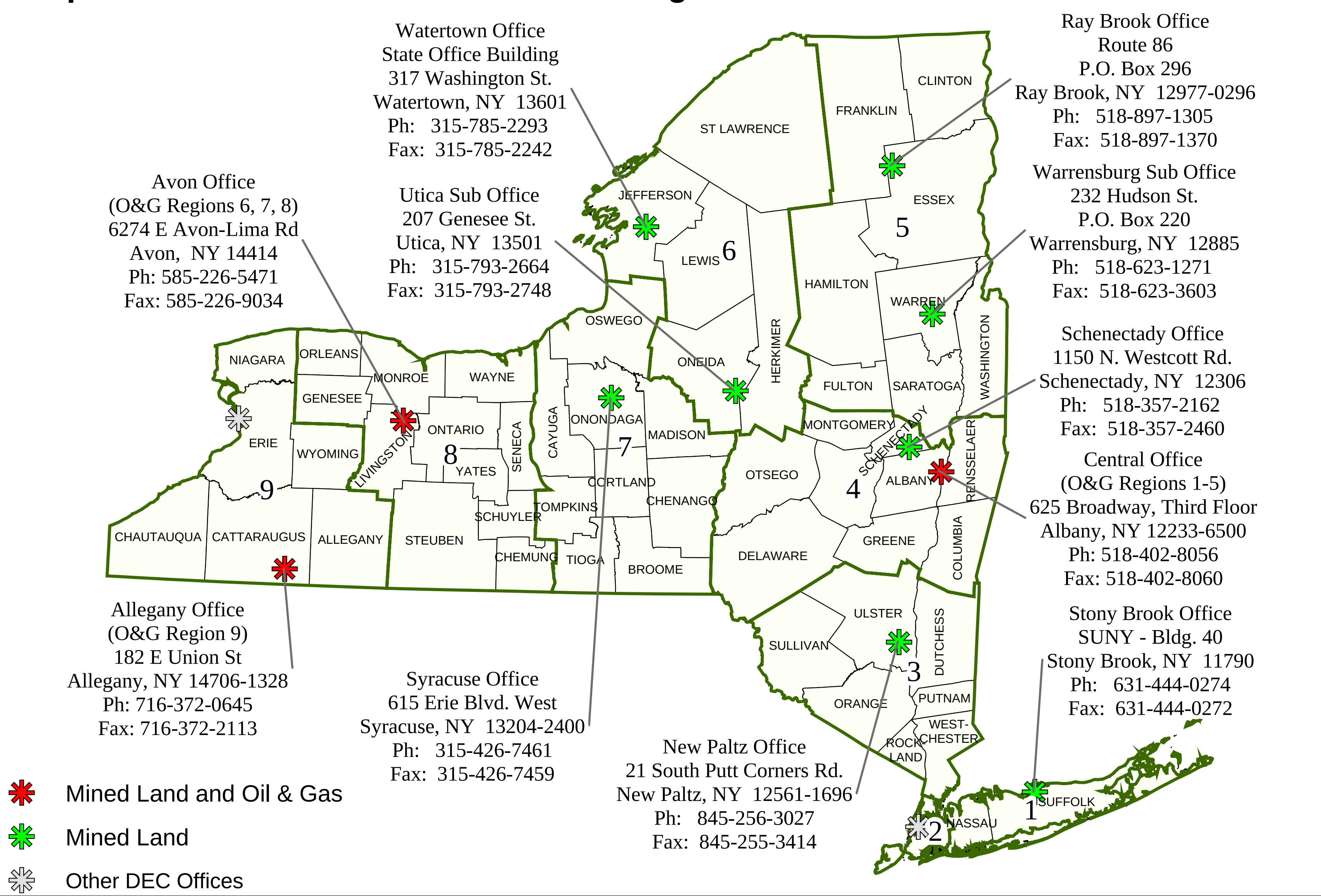
Details on the economic rank for major mine products and location of the largest mines

Appendices

Map 1 - Division of Mineral Resources Regional Service Areas



2008 New York Oil & Gas Industry
At a Glance

Production and Market Value

Gas	50.320 bcf	Value down	7%
Oil	397,060 bbl	Value up	25%
Total Market Value		$488 Million	

Revenues In Millions

State Leasing	$2.2 Million
Local Govt. (est.)	$14.6 Million
Landowner Royalties (est.)	$61.0 Million

Financial Security
Plugging & Reclamation

$24,663,543

State Leasing

91 leases covered 63,591 acres

226 productive wells

All Reported Wells 14,513

Active Wells

Natural Gas	6,675
Oil	3,617
Gas Storage	929
Solution Salt	131

Underground Gas Storage

24 facilities, 79% full at year-end

Total Storage Capacity	223 bcf
Working Gas Capacity	113 bcf
Max. Deliverability	2.127 bcf/day

Solution Mining

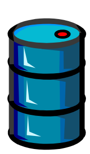
Five facilities produced 1.93 billion gallons of brine (2.25 million metric tons salt)

Natural Gas & Oil Abbreviations

Abbreviations for natural gas volume measurements:

mcf	**thousand cubic feet**
mmcf	**million cubic feet**
bcf	**billion cubic feet**

Crude oil is also measured by volume. One barrel equals 42 gallons.



bbl barrel

What's an MCF Do ?

Roughly 4.2 million households in New York use natural gas for home heat, cooking and heating water. It takes just 69 mcf per year to heat the average New York home.* The State's 2008 production of 50.3 bcf was enough to heat 729,269 homes.

* 2005 NYS Energy Fast Facts, NYSERDA

Market Value and Economic Benefits

Market Value

Estimated total market value for New York's oil and gas decreased 6% to $488 million in 2008. Breaking down the figures in more detail, the value of natural gas decreased from $486 million in 2007 to $450 million in 2008. New York produces much less oil than gas, but oil's market value rose by 25%, from $30.4 million in 2007 to $38.1 million in 2008.

Tax Revenues to Local Governments

Communities in oil and gas producing areas also benefit from the industry's activity. The Division estimates that real property taxes on 2008 production totaled roughly $14.6 million, a 6% decrease from the previous year.

To dampen the impact of fluctuating oil and gas prices, local governments assess their taxes on a unit of production value determined by the NY State Division of Equalization and Assessment using a five-year average.

State Lease Oil and Gas Prices

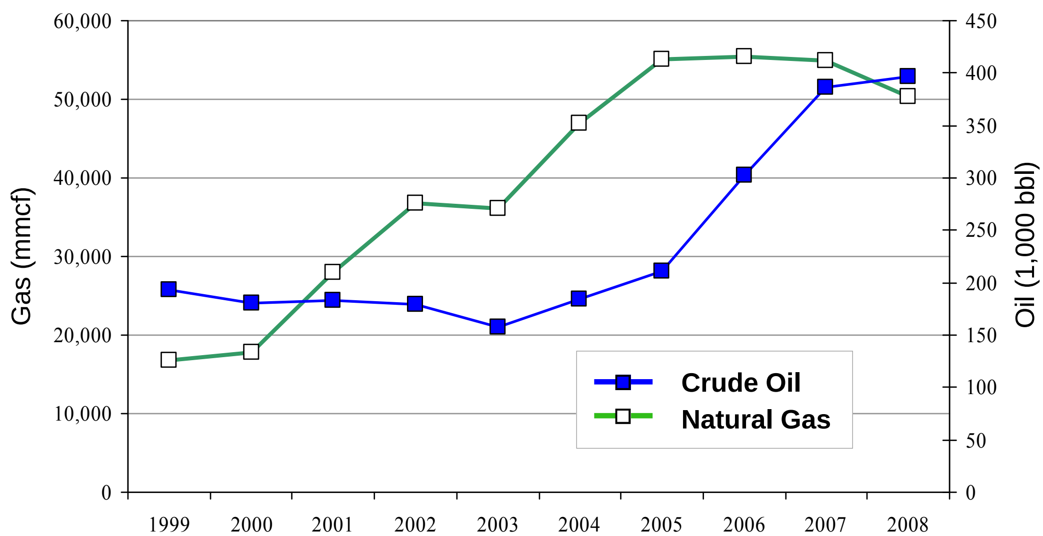
The average wellhead natural gas price of $8.94 per mcf in 2008 was up slightly from $8.85 in 2007. The average 2008 oil price of $99.29 per bbl was up 26% from $78.59 in 2007. These average prices were obtained from royalty payments made to New York for leases on State lands.

Landowner Royalties and Landowner Wells

The majority of landowners with producing oil and gas leases receive a royalty from the well operator. Based on an average royalty of one-eighth of the production value, the Division estimates that landowners in New York received roughly $61 million in royalties in 2008.

In addition, roughly 500 of New York's gas well operators (mostly landowners) own just one well. Typically, the wells are no longer considered commercially productive, but can provide enough gas to help reduce or eliminate the landowner's home heating costs.

Chart 1 - New York State Oil and Gas Production, 1999 - 2008



Production of Oil and Gas

Natural Gas Production

New York's reported natural gas production for 2008 was 50.320 bcf, down from 54.619 bcf in 2007. Roughly 34.8 bcf of gas came from just 100 producing Trenton-Black River wells, with one (1) well alone producing 2.1 bcf. Production from other formations rose 14% as a group, with notable increases from the Queenston (49%) and Herkimer-Oneida-Oswego (135%).

In 2008 Steuben County was the top gas-producing county. Steuben and Chemung counties accounted for 65% of New York's 2008 production. Chautauqua County continued to rank third (see Table 1).

Oil Production

In 2008 New York's oil production rose 3% to 397,060 barrels, the highest since 1992. From 2005 to 2008 oil reserves more than doubled.

Top Producers

In 2008 the top gas producer was Fortuna Energy Inc., at 31.34 bcf of gas, and the top oil producer was East Resources, at 122,832 bbl of oil. Tables 2 and 3 on page 12 show the top 10 oil and gas producers. Tables 5 and 6 on page 16 show the top 10 Trenton-Black River wells and fields.

Table 1 - Top 10 Gas Counties, 2008

County	Gas (mcf)	Active Gas Wells	Average mcf/Well
Steuben	17,146,368	69	248,498
Chemung	15,626,276	43	363,402
Chautauqua	6,758,069	3,438	1,966
Erie	1,961,665	961	2,041
Seneca	1,606,948	214	7,509
Cattaraugus	1,593,604	528	3,018
Schuyler	1,060,947	18	58,942
Tioga	1,038,093	1	1,038,093
Cayuga	838,287	291	2,881
Genesee	767,032	519	1,478

For Further Details

Map 2 on page 13 gives production information by town. Table 4 on page 14 gives production by geologic formation. For further production details, please visit our website at **www.dec.ny.gov/energy/1601.html** .

Chart 2 - Producing Formation for NY Natural Gas, 2003 - 2008

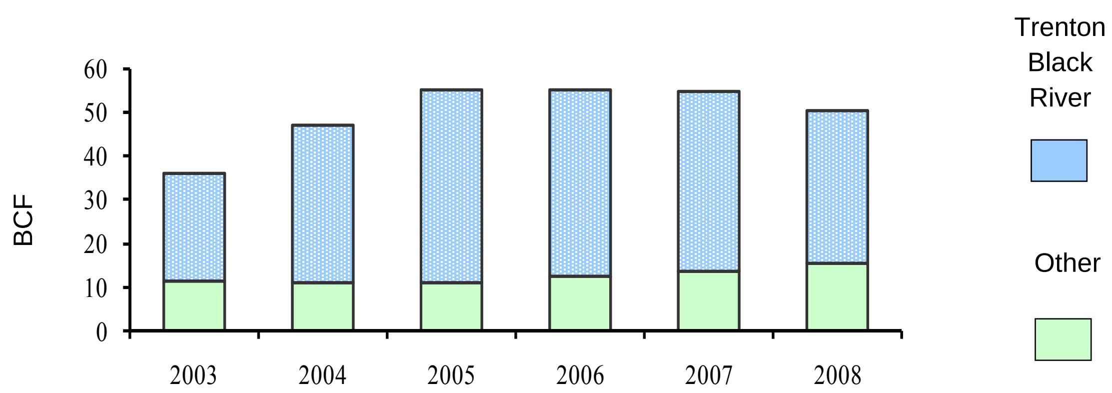


Table 2 - Top 10 Gas Producing Companies, 2008

Company	2008 Gas (mcf)	2007 Rank	2008 Change
1. Fortuna Energy, Inc.	31,344,702	1	-20%
2. Chesapeake Appalachia, LLC	5,579,586	2	+63%
3. Range Resources-Appalachia, LLC	2,288,171	3*	-9%
4. U. S. Energy Development Corp.	1,601,132	5	+66%
5. EnerVest Operating, LLC	1,142,917	New**	NA
6. Nornew, Inc.	1,068,956	4**	-45%
7. United States Gypsum Co.	558,918	6	-1%
8. Stedman Energy, Inc.	530,507	>10	+27%
9. Universal Resources Holdings, Inc.	468,164	9	+5%
10. Seneca Resources Corp.	428,129	7	-10%

* Transfer from Great Lakes Energy

** Well transfers from Nornew to EnerVest

Table 3 - Top 10 Oil Producing Companies, 2008

Company	2008 Oil (bbl)	2007 Rank	2008 Change
1. East Resources, Inc.	122,832	1	-34%
2. McCracken, Carl A. III	35,081	2	+42%
3. Case Brothers Inc.	29,849	3	+102%
4. Dallas Energy, LLC	23,206	6	+143%
5. Copper Ridge Oil, Inc.	21,163	10	+183%
6. Nathan Petroleum Corp.	11,781	4	-9%
7. Johnson, Mark & Troy	10,806	8	+44%
8. Otis Eastern Service, Inc.	10,003	5	-14%
9. Pefley Oil & Gas, Inc.	8,757	>10	+497%
10. Snyder Brothers, Inc.	7,647	>10	+35%

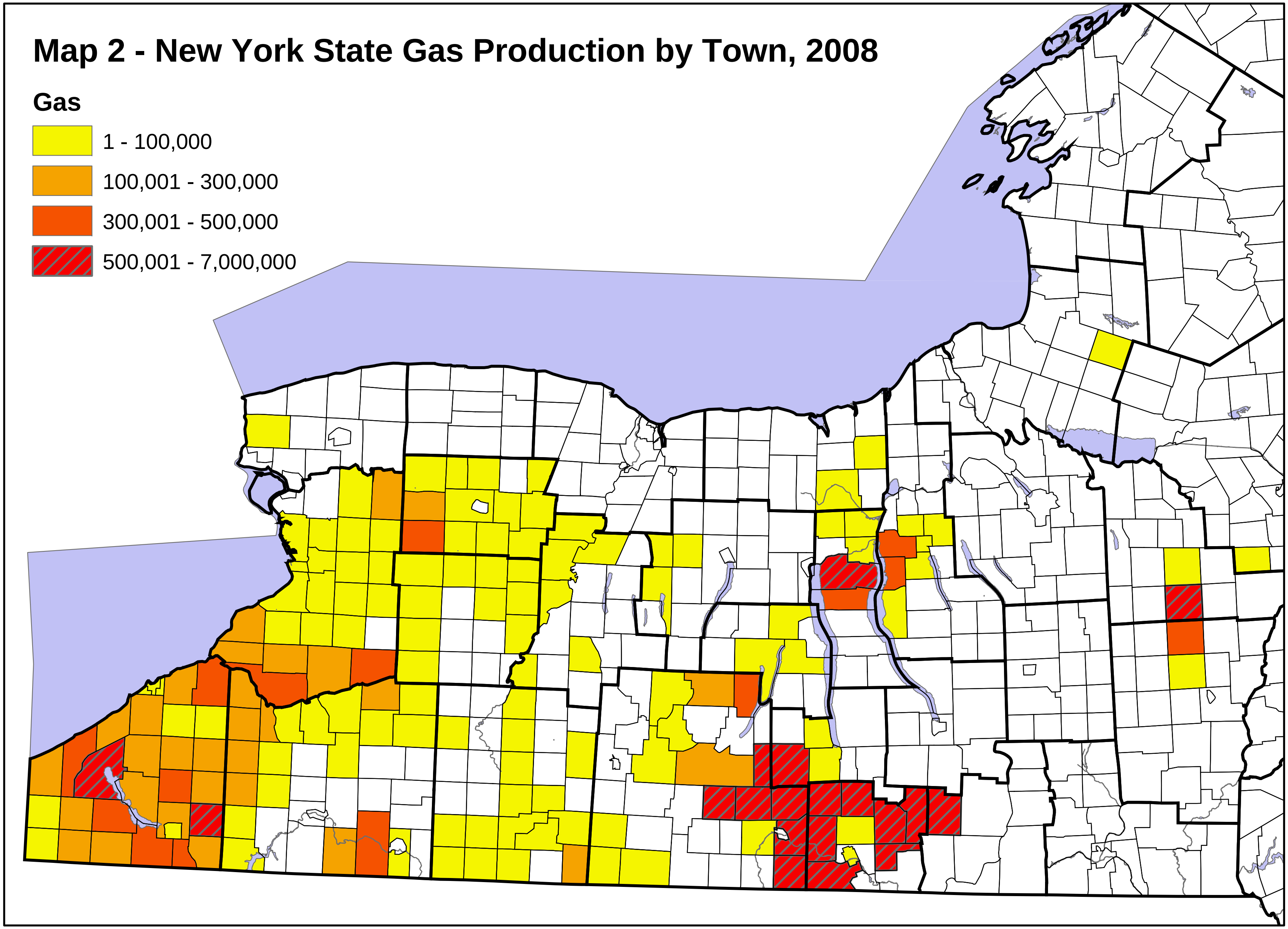

Map 2 - New York State Gas Production by Town, 2008
Gas
1 - 100,000
100,001 - 300,000
300,001 - 500,000
500,001 - 7,000,000

Table 4 - Production by Geologic Formation, 2008

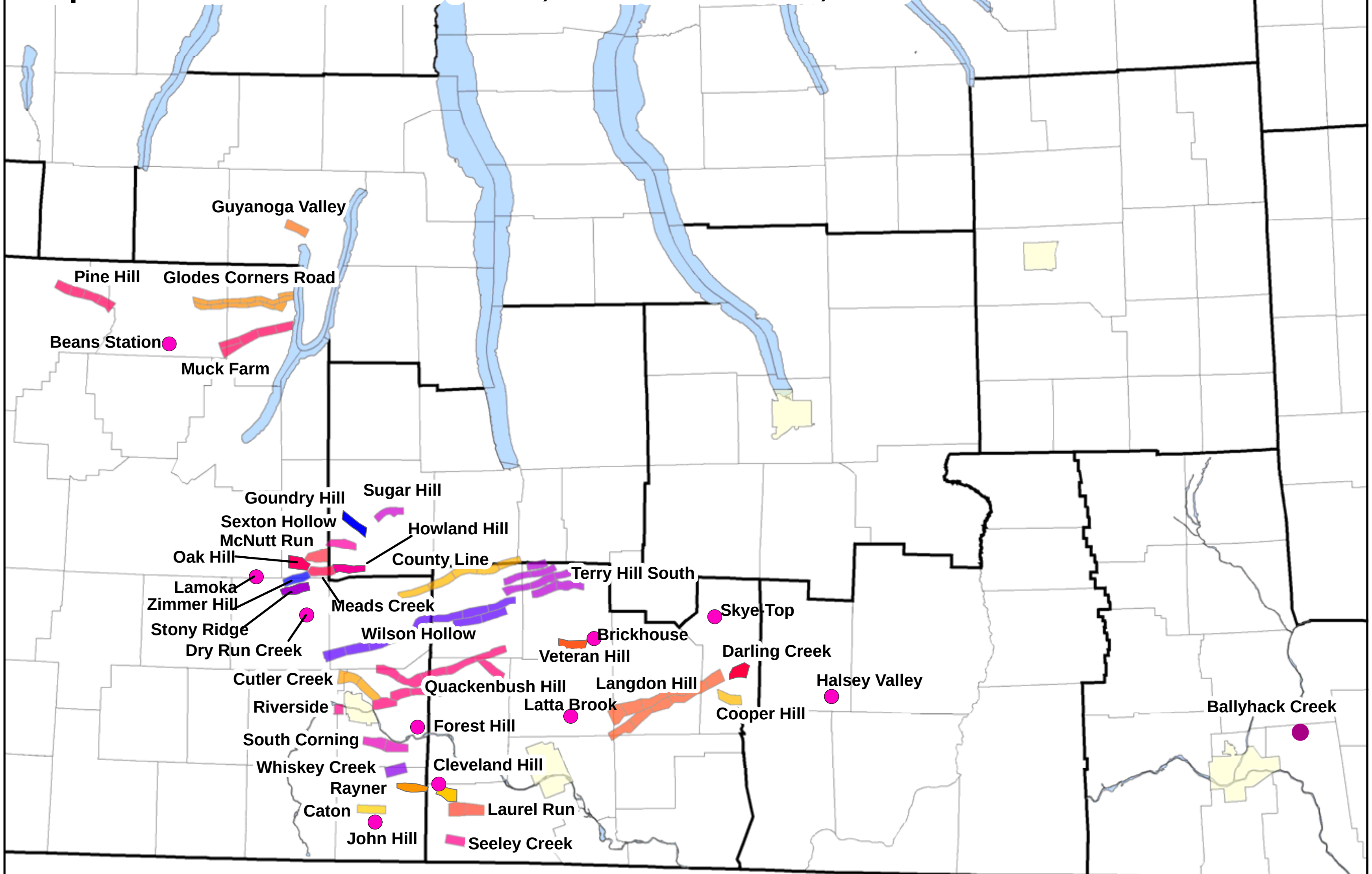
Formation	Wells[1]	Gas (mcf)	Oil (bbl)
Devonian Shale	28	24,523	0
Undifferentiated Canadaway Group[2]	4,441	355,612	292,553
Perrysburg	1,069	297,751	68,140
Tully	11	16,958	1,058
Hamilton	3	0	0
Marcellus	28	64,063	0
Onondaga	76	48,537	1,528
Oriskany	40	190,854	0
Helderberg	1	0	0
Akron	29	13,708	0
Herkimer-Oneida-Oswego	79	935,557	0
Medina	6,551	10,302,222	1,412
Bass Island	82	136,516	13,614
Queenston	589	2,460,968	0
Trenton	13	41,872	0
Black River	138	34,768,042	0
Little Falls	1	10,674	0
Theresa	25	534,866	0
Other	478	117,160	5,500

1 Active, temporarily abandoned and shut-in wells

2 Undifferentiated Canadaway Group includes Glade, Richburg, Bradford, and other well-known oil producing formations

To see a stratigraphic column of New York's geologic formations go to http://www.dec.ny.gov/energy/33893.html

Map 3 - Trenton-Black River Fields, Central New York, 2008*



* Includes historic fields not currently producing

Table 5 - Top 10 Wells, Trenton-Black River Production, 2008

Well Name	API Identification Number	2008 Production (bcf)	County/ Field
Gross D1	31101239020000	2,115,603	Steuben/Quackenbush Hill
Dzybon 1	31101238670000	1,967,857	Steuben/Forest Hill
Hartman, BJ 1	31101232270000	1,622,600	Steuben/Rayner
Drumm J. 1A	31101239850100	1,618,175	Steuben/Green Hill
Stoscheck 1	31015238140000	1,530,278	Chemung/Darling Creek
Lovell 1323	31015228310000	1,470,724	Chemung/Quackenbush Hill
Cotton-Hanlon 2	31015239870000	1,208,513	Chemung/Cramer Hollow
Gillis 1	31101231100000	1,105,742	Steuben/Rayner
Michaloski 1	31101239210000	1,038,255	Steuben/Caton
Winter G 1A	31107238550100	1,038,093	Tioga/Halsey Valley

Table 6 - Top 10 Fields, Trenton-Black River Production, 2008

Field Name	2007 Production (bcf)	2008 Production (bcf)	Cumulative Production Year-End 2008	First Year of Production
Quackenbush Hill	9,555,996	7,801,356	95,729,531	2000
Rayner	3,978,014	2,728,342	12,445,618	2005
Langdon Hill	1,716,659	2,260,014	11,481,080	2001
Wilson Hollow	3,291,519	2,111,885	44,163,535	1999
Darling Creek	3,973,466	1,530,278	9,443,618	2006
Whiskey Creek	952,809	860,383	5,668,875	2003
Seeley Creek	860,920	398,253	5,864,319	2004
Muck Farm	469,284	351,543	9,211,522	1999
Terry Hill South	446,737	231,748	8,871,405	2001
Glodes Corners Road	155,487	144,410	10,027,556	1996

Drilling Permits and Well Completions

Drilling Permits

DEC issued 737 drilling permits in 2008, up 28% from the previous year. This included 430 natural gas, 250 oil, 22 geothermal, 14 brine, 12 stratigraphic, and 9 underground gas storage permits.

In 2008 DEC issued permits for wells in 25 counties; the top 3 were Chautauqua County (142), Cattaraugus County (140), and Allegany County (134). Most of the oil drilling permits were issued for Allegany (125) and Cattaraugus (94) counties. Chautauqua (117) and Erie (72) counties had the highest number of gas permits.

Well Spuds and Completions

The number of wells spud (started) in 2008 was 562. The number of permits issued in 2008 was up 28% from the previous year. The total number of completions decreased 6% to 500. Gas well completions remained almost exactly the same as in 2007. Oil well completions fell by 13% from 2007.

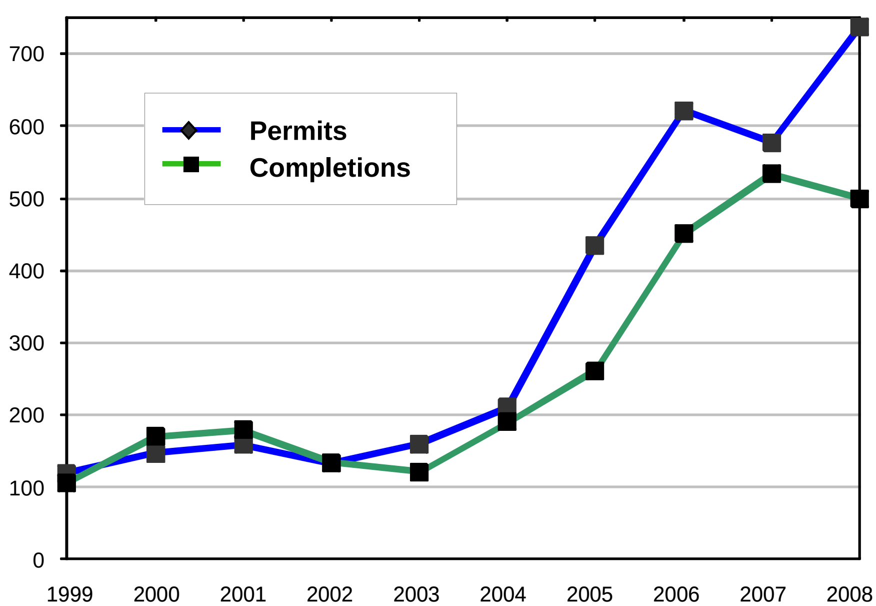
Wildcats and Extensions

Operators drilled 68 gas wildcat wells, 1 oil wildcat well, and 18 gas extension wells in 2008.

Formations Permitted

Industry interest in the Black River and Trenton formations continued, with 33 permits issued in 2008. Other primary gas targets included the Medina and Queenston for a total of 331 permits. The Division issued 246 permits for the State's main oil-producing formations (Perrysburg and Undifferentiated Canadaway Group). Nine permits were issued for the Marcellus in 2008, and 5 vertical Marcellus wells were drilled during the year.

Chart 3 - Drilling Permits and Completions, 1999 - 2008



Drilling Permits, 2008

Gas	429
Oil	250
Other	58
Total	737

Well Completions, 2008

Gas	270
Oil	172
Other	58
Total	500

Marcellus and Other Shales

The Marcellus Shale is a black shale that forms the basal unit of the Hamilton Group in New York State. It is geographically extensive, covering an area of approximately 54,000 square miles in the Appalachian Basin states of Kentucky, New York, Ohio, Pennsylvania, and West Virginia. A 2002 estimate by the U.S. Geological Survey put basin-wide Marcellus natural gas reserves in the range of 30 trillion cubic feet (tcf). However, by 2008 the estimate had climbed closer to 400 tcf based on continued evaluation of Marcellus drilling in Pennsylvania and West Virginia.

In 2008 DEC received 58 permit applications for Marcellus wells and 13 of those were for horizontal wells. New York State's 2008 Marcellus production totaled 64,063 mcf from 15 vertical wells. The Marcellus is one of several important low-permeability shale gas reservoirs in New York State; the Utica Shale in Otsego County and the Trenton Group shales in Madison County also continue to attract interest.

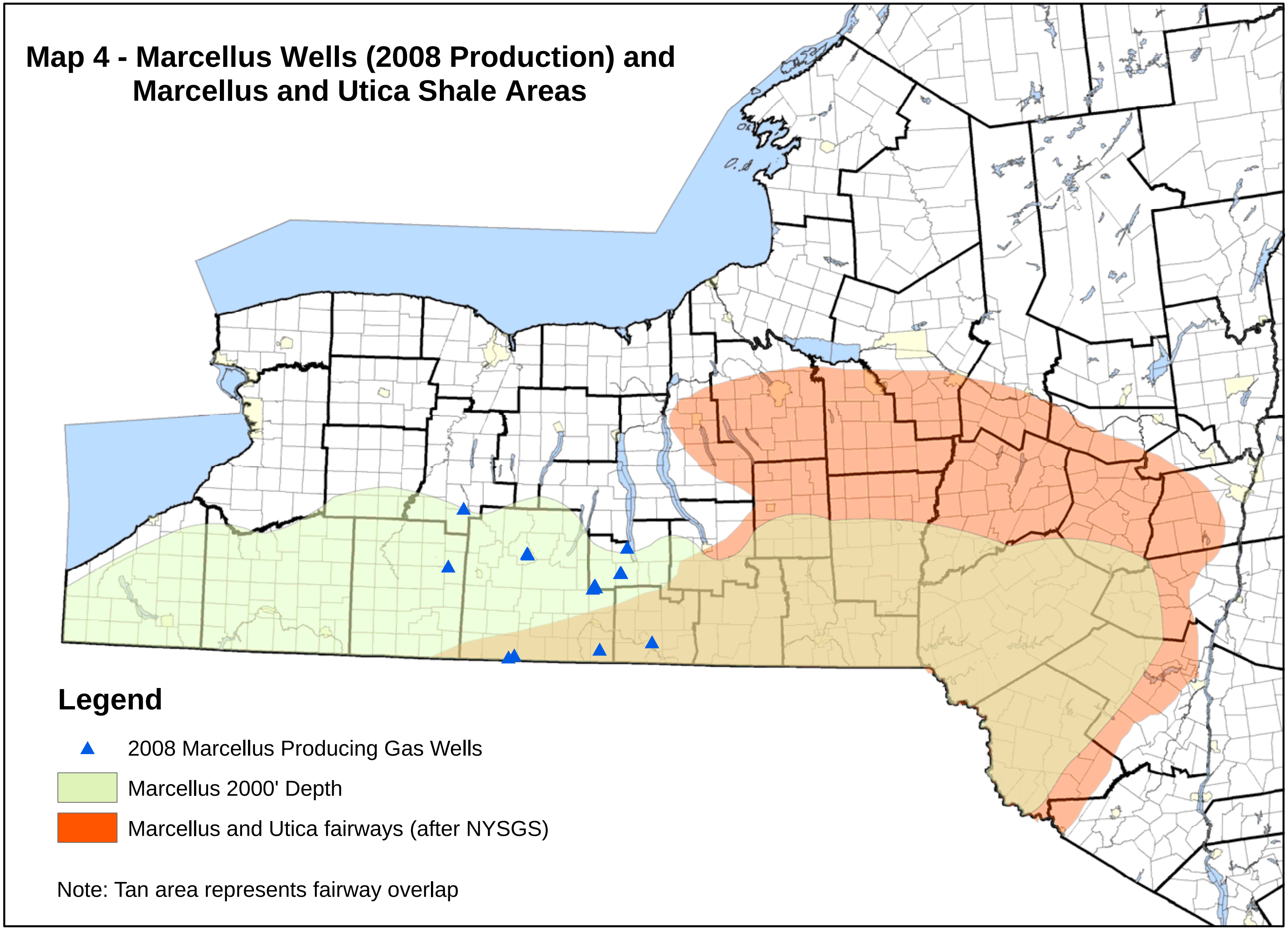
Advances in horizontal drilling and hydraulic fracturing technologies, together with a sharp rise in natural gas commodity prices, spurred leasing activity. The Marcellus became the focus of a great deal of activity in the Appalachian Basin during 2008. Landmen were seeking to lease mineral rights in Delaware, Broome, Sullivan, and other counties. Press reports stated that signing bonuses up to $2,700/acre and royalty payments of up to 18% were being offered to landowners. Landowner coalitions formed all along the Southern Tier, with one 300-member group in the New York-Pennsylvania border region near Port Jervis, NY executing a lease for roughly $90 million.

Some of the more active players in this "gas rush" were Chesapeake Appalachia, LLC; Fortuna Energy, Inc.; and East Resources, Inc. As a result of the heightened activity, Division staff spent considerable time with municipal and county leaders, as well as with members of the public, discussing the State's Oil and Gas Regulatory Program.

On July 23, 2008, the Governor signed amendments to Article 23 of the Environmental Conservation Law designed to address well spacing for horizontal wells. Importantly, the Governor also directed DEC to prepare a Supplement to its 1992 Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Program (GEIS) to address horizontal drilling and high volume hydraulic fracturing in the Marcellus Shale and other low permeability natural gas reservoirs.

The document's development began with six Scoping Meetings held in the Southern Tier from November to early December 2008, where the public could recommend topics to be covered in the Supplemental GEIS (SGEIS); DEC also accepted comments submitted directly to the agency until mid-December. Upon completion of the Scoping Process, the list of potential impacts to be covered included: visual; noise; air quality; water resources; significant habitats and endangered species; invasive species; floodplains; wetlands; road use; cumulative impacts; community character; and areas of historical, architectural, and archeological significance.

Historically, shale wells in New York have been drilled vertically and then hydraulically fractured with 80,000 gallons or less of water. However, based on recent successes in shale plays in other states, the most efficient method for developing low-permeability shale reservoirs is now horizontal drilling combined with high-volume hydraulic fracturing. Horizontal drilling is not new to New York State; it was used to develop the Trenton-Black River play in the south-central Finger Lakes Region. However, high-volume hydraulic fracturing - using millions of gallons of water per well - was never contemplated during preparation of the GEIS and, is, therefore, being addressed in the SGEIS. Map 4 shows the approximate area of interest in the Marcellus (roughly where the formation is 2,000 or more feet deep) and the Marcellus and Utica fairways, as mapped by the NYS Geologic Survey. A fairway is the area considered likely to produce economic quantities of gas.


Map 4 - Marcellus Wells (2008 Production) and
Marcellus and Utica Shale Areas
Legend
2008 Marcellus Producing Gas Wells
Marcellus 2000' Depth
Marcellus and Utica fairways (after NYSGS)
Note: Tan area represents fairway overlap

Compliance and Enforcement

Inspections

In 2008 Oil and Gas staff traveled 95,672 miles to perform 2,445 well site inspections. Staff inspect well sites:

- during permit application review to check environmental and public safety issues;
- during drilling to check on well site construction and drilling permit compliance;
- during the operating phase to check for leaks, spills, or other potential problems;
- to ensure that well plugging and site reclamation meet requirements; and
- upon receipt of a well transfer request.

DEC staff perform follow-up inspections to ensure any violations are properly remediated.

Compliance Enforcement

Violations are handled with a mixture of enforcement tools, remediation requirements and penalties. In 2008 the Oil and Gas Program assessed $10,500 in fines and penalties.

Permit Fees

Total oil and gas permit fees collected by the Division equaled $908,090 in 2008, of which $73,700 was deposited in the Oil and Gas Account; this fund is dedicated to plugging orphan and abandoned wells.

DEC Oil and Gas staff perform over 2,000 well inspections per year. Here the inspector is checking to make sure the well is in compliance before DEC approves transfer of the well to a new company.

State Land Leasing

At the end of 2008 the Division managed 91 leases covering roughly 63,591 acres of State land, a decrease from the previous year's 83,021 acres. The big drop was from expiration of 15 leases awarded at the 2003 lease sale. The roughly 20,000 acres of land involved could be offered for lease again in a future sale.

At year-end 2008 the State was earning royalties from 108 productive oil and gas wells physically located on State lands and another 118 producing wells on adjacent or unitized lands. These wells are associated with 61 State leases.

The 226 wells produced 17.8 bcf of natural gas and 4,819 bbl of oil. The average prices paid were $8.95 per mcf for gas and $89.13 per barrel of oil.

In 2008 the State received total leasing revenues of $2.2 million, down 82% from $11.8 million in 2007. The steep drop was due to the fact that no lease sale was held in 2008.

- **Delay Rentals -** Operators submitted a total of $97,269 in delay rentals. This figure was down 42% from the $166,868 collected in 2007.

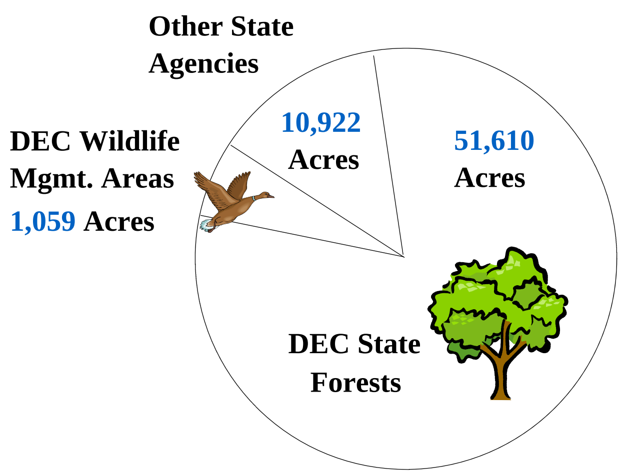
- **Royalties -** The State received $1,866,519 in royalty revenue from oil and gas production on 61 leases in nine counties (32,452 acres), down 24% from $2,466,312 in 2007.

- **Storage Leases -** Fourteen storage leases added $211,927, up 59% from 2007. The majority of New York's storage lease acreage is in Cattaraugus County.

- **Bonus Bids -** No bonus bids were received because there was no State land lease sale in 2008.

Table 7 - Total Leasing Revenues, 2003 - 2008	
2003	$5,326,927
2004	$765,782
2005	$3,439,670
2006	$3,296,932
2007	$11,767,813
2008	$2,175,715

DEC Managed Oil and Gas Leases



For more information, see the 2008 Oil & Gas Leasing Report at **http://www.dec.ny.gov/energy/1579.html**

Plugging Permits and Bonds

2008 Plugged Wells and Bonds

At year-end DEC held $24.7 million in financial security to guarantee well plugging and well site reclamation. This represented an increase of 7% from $23.1 million in 2007.

Financial Security, 2008

$24.7 Million

At the end of production a well must be plugged with cement at proper intervals, the equipment must be removed, and all disturbed land, including the access road, must be reclaimed. In 2008 operators plugged 221 wells in accordance with requirements set by DEC in plugging permits.

Table 8
Plugged Wells, 2008

Oil	172
Gas	37
Other	12
Total	221

Much of the plugging activity was in the old oilfields of western New York. Almost 78% of the plugging jobs were oil wells, 17% gas wells, and the remaining 4% a mix of other regulated well types.

Plugging occurred in 16 counties, however, almost 50% of the plugging jobs were in Allegany County and another 30% were in Cattaraugus County. The vast majority of plugging jobs involved old oil wells, particularly in the Richburg Field.

Some of this plugging activity can be attributed to the recent high prices for oil. During the process of redeveloping an old oilfield, operators may need to plug old or inactive wells.

Abandoned and Orphaned Wells

Old Historic Well Problems

Abandoned wells can leak oil, gas and/or brine; underground leaks may go undiscovered for years. These fluids can contaminate ground and surface water, kill vegetation, and cause public safety and health problems.

Historically, abandoned wells have been discovered in the woods, along roadsides, and in residential yards, playgrounds, and parking lots. They've even been discovered inside buildings, and underwater in wetlands, streams and ponds.

2008 Status Report

Abandoned, unreported and inactive wells continued to be a problem despite high oil and gas prices. In 2008 a total of 284 operators reported 3,071 wells with zero production. Another 133 unreported wells are considered abandoned. This is in addition to over 4,717 orphan wells in the Department's records. Enforcement actions have reduced the number of unreported wells, but their numbers remain significant.

DEC has at least partial records on 39,000 wells, but estimates that over 75,000 oil and gas wells have been drilled in the State since the 1820s. Most of the wells date before New York established a regulatory program. Many of these old wells were never properly plugged or were plugged using older techniques that weren't as reliable and long-lasting as modern methods.

Every year while conducting scheduled inspections or investigating complaints, DEC staff discover more abandoned wells. Extensive courthouse research is often required to identify a well's previous owners. Many of these cases take several years to resolve as DEC pursues legal action against the responsible parties.

Why Do We Keep Finding "New" Abandoned Wells ?

Most abandoned wells were drilled many decades ago so:

- they were not registered with the State and there are often no maps available;
- surface equipment is often gone that would make them easier to spot; and
- they may be hidden by thick underbrush, standing water, or other subsequent uses of the land.

Oil & Gas Account

New York has an Oil and Gas Account which was created to plug problem abandoned wells. It is funded by a $100 per well permit fee; at the end of 2008 the balance was $377,824. DEC has over 600 wells on its priority plugging list. Since the funds are insufficient to plug all the priority wells, DEC continues to pursue other mechanisms to plug abandoned wells.

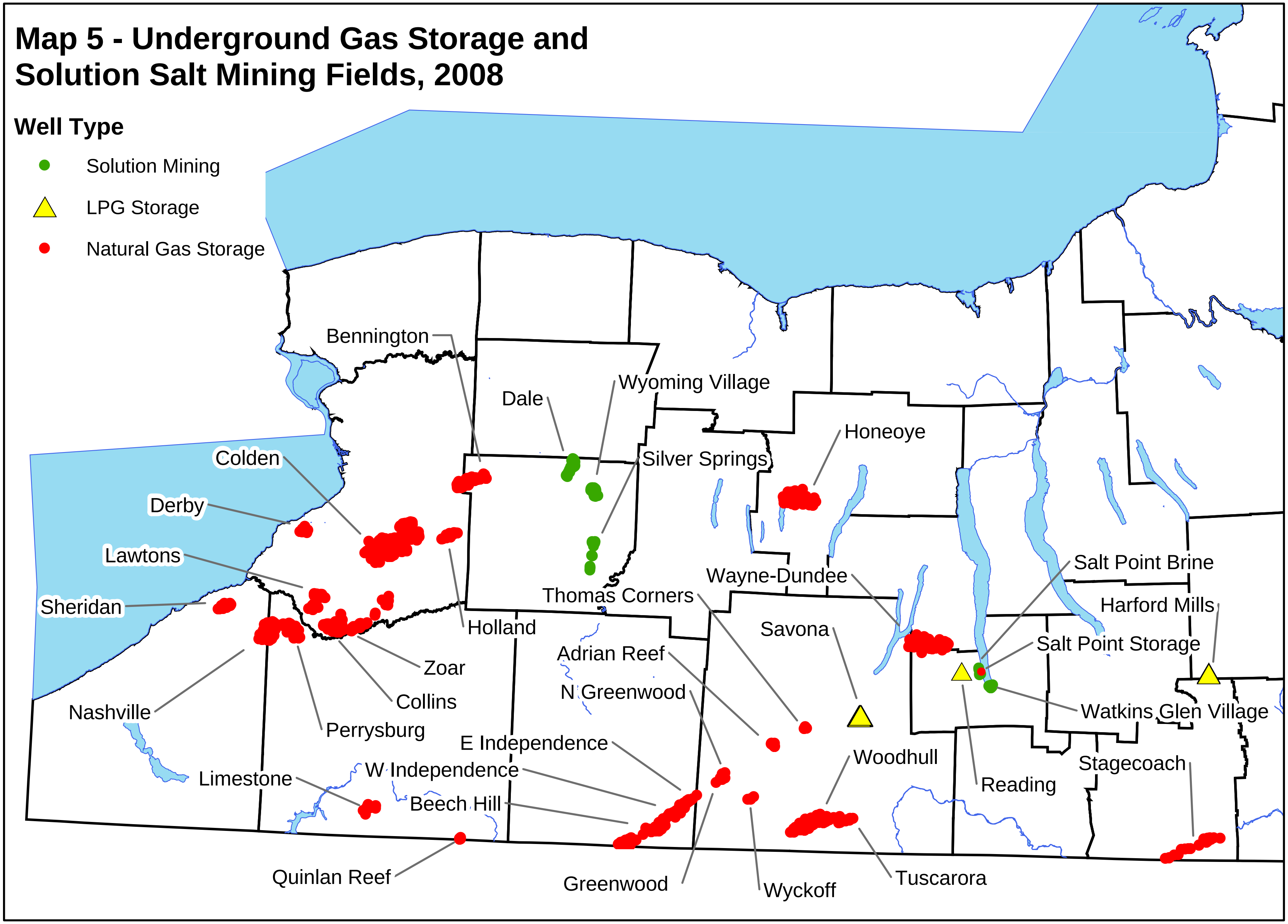
DEC-Coordinated Plugging Efforts

In 2008 Division staff worked on Oil and Gas Account contracts for two major plugging projects involving abandoned oil wells. One was a $190,000 contract to plug 45 wells on the Thornton-Bradley and Warfield leases in the Town of Alma, Allegany County. The wells were in an advanced state of disrepair. The plugging contract was formally approved in 2008, but field crews to perform the work could not be scheduled until the spring of 2009.

The other project involved a $150,000 contract to plug 25 wells on the Knox Lease in Cattaraugus County. The wells were causing water supply contamination problems. Thirteen of the 25 wells on the Knox Lease were plugged in 2007 and the remaining 12 were plugged in early 2008. During the 2008 plugging activity, 4 other abandoned wells were discovered and subsequently plugged. For these 4 wells, the Division used Environmental Benefit Project funds from an unrelated settlement with Bath Petroleum Storage, Inc.

Division staff continued working with the U.S. Environmental Protection Agency (USEPA) and the U.S. Coast Guard (USCG) to plug wells with federal funds from the Oil Pollution Act of 1990. This money can be used for wells that leak oil or threaten to leak oil to the navigable waters of the United States.

As a direct result of DEC staff efforts, USEPA has undertaken several plugging projects in New York State. In 2008 USEPA focused on the Moore Lease in the Town of Bolivar, Allegany County. DEC had previously plugged the 43 highest-priority wells on the lease with a $100,000 settlement from the estate, but lacked the funds to tackle the remaining 182 wells. In 2008 USEPA plugged 78 of the wells and agreed to continue the project in 2009. The abandoned and leaking wells on this lease had been the subject of DEC enforcement actions for decades.


Map 5 - Underground Gas Storage and
Solution Salt Mining Fields, 2008
Well Type
Solution Mining
LPG Storage
Natural Gas Storage
Bennington
Dale
Wyoming Village
Silver Springs
Honeoye
Colden
Derby
Lawtons
Sheridan
Holland
Zoar
Collins
Nashville
Perrysburg
Limestone
Quinlan Reef
Thomas Corners
Wayne-Dundee
Savona
Adrian Reef
N Greenwood
E Independence
W Independence
Beech Hill
Greenwood
Wyckoff
Woodhull
Tuscarora
Reading
Salt Point Brine
Harford Mills
Salt Point Storage
Watkins Glen Village
Stagecoach

Underground Gas Storage

In 2008 there were 24 natural gas and 3 liquefied petroleum gas underground storage facilities operating in 10 counties in the western and central parts of New York State.

Natural Gas Storage

At year-end 2008 the combined total capacity of all the underground natural gas storage fields in New York State was 223.3 bcf and the maximum deliverability per day was 2.13 bcf. Working gas capacity was 112.7 bcf. Operators reported that these storage fields were 79% full at the end of the year, with 176.0 bcf in storage.

Seven different companies operate the 24 underground natural gas storage fields in New York State, with over half owned by National Fuel Gas Supply. Twenty-three of the facilities use depleted natural gas reservoirs in the Onondaga, Oriskany and Medina formations and the remaining one uses a solution-mined cavern in the Syracuse salt formation. These formations range in depth from 1,500 to 5,000 feet below the earth's surface.

In 2008 Division staff received an application for a permit modification for the Thomas Corners storage field in Steuben County. The facility was originally permitted by the Department in 1996, but was never placed in service. Ownership of the facility was transferred to Arlington Storage Company, LLC (ARS) in 2007. The Thomas Corners storage field is projected to be in service in 2009 after additional state and federal review and site construction.

Liquefied Petroleum Gas Storage

New York's three liquefied petroleum gas (LPG) underground storage facilities are located in Cortland, Steuben and Schuyler counties. At year's end Department records showed Inergy Midstream, LLC (Inergy) as the owner of the facility in Steuben County and TE Products Pipeline Company, LLC (TEPPCO) as the owner of the facilities in Cortland and Schuyler counties. TEPPCO purchased the facility formerly owned by New York LP Gas Storage, Inc. (NYLPG) in Cortland County, and Division staff approved the transfer of the facility's underground storage permit in February 2007. At year-end 2008 total LPG capacity of the three facilities was 150.90 million gallons, while product in storage was 33.25 million gallons.

LPG is stored in underground caverns excavated in the shales of the Genesee Group at the TEPPCO facility in Schuyler County, and solution-mined out of the Salina Group salt formations at the other two facilities. The Salina Group salt formations are the same rock units mined by New York's five solution mining facilities.

In 2005 the Department and Bath Petroleum Storage, Inc. (BPSI) executed an Order on Consent regarding the LPG facility in Steuben County. As the current owner, Inergy assumed responsibility for BPSI's legal obligations, including the requirement to fund an Environmental Benefit Project to plug orphaned wells. By the end of 2008 Inergy had paid $275,000 into a dedicated account.

Permit Applications

In 2008 Division staff were also engaged in reviewing four other permit applications submitted during previous years. The applications included three from National Fuel Gas Supply Corp. (NFGSC) and one from Inergy (originally submitted by BPSI).

In addition to conducting its own review of the underground natural gas storage projects, the Department routinely participates as a cooperating agency in the Federal Energy Regulatory Commission's (FERC) permitting process. Division staff provide input to FERC for Environmental Assessments and accompany FERC reviewers on site visits. However, FERC's jurisdiction is limited to interstate natural gas facilities, so FERC was not involved in the above-mentioned permit for Inergy's LPG project.

Solution Salt, Geothermal and Stratigraphic Wells

While oil and gas wells are the best known part of the Division's regulatory program, several other types of wells drilled in a similar fashion are subject to permit requirements. Solution mining wells have been drilled into New York's underground salt beds since the 1800s; the wells inject fresh water and bring up brine. Permits for solution mining wells include special drilling, operating and plugging requirements tailored to that industry.

The Division also regulates geothermal and stratigraphic wells over 500 feet deep. Geothermal wells play an important role in energy conservation. Stratigraphic wells provide essential information on underground rock formations and subsurface conditions.

Solution Salt

New York's five solution salt mining facilities, operated by U.S. Salt, Cargill, Morton, Texas Brine, and Occidental Chemical, produced 1.93 billion gallons of brine in 2008, a decrease of 2% from 2007. Three of the solution mining facilities are located in Wyoming County and the other two are in Schuyler County.

In 2008 solution mining operators submitted 12 drilling permit applications, compared to 13 applications in 2007. Seven solution mining wells were plugged in 2008.

The value of New York's solution salt mining production is estimated at over $100 million. For years New York has ranked third nationally in total volume of salt production (combined brine and rock salt).

Geothermal

At year-end 2008 the State had 90 geothermal wells that required drilling permits from the Division of Mineral Resources because they were deeper than 500 feet. While a few deep geothermal wells can be found scattered around the Capital District, central New York and the Adirondacks, the majority are in the New York City area.

In 2008 the Division received 24 geothermal well drilling applications and issued 22 permits, all in New York City or Westchester County.

Stratigraphic

The Division received 13 drilling permit applications for stratigraphic wells in 2008 and issued 12 permits before the end of the calendar year.

Uses for Geothermal Wells

Geothermal/geo-exchange wells regulated by DEC (deeper than 500 feet) have been drilled to heat and cool a wide range of buildings:

- Residential and Commercial Projects
- Education Center
- Fashion Design Studio
- Historic Buildings
- Library
- Lion House at the Bronx Zoo
- Museum/ Research Facility
- Religious Seminary

Carbon Capture and Storage

The Division of Mineral Resources did not receive any applications for carbon capture and storage or geologic sequestration projects in 2008. In fact no such projects currently exist in New York State. However, there is much industry, government and public interest in this concept as one possible means to reduce global warming from CO_2 generation and release.

Important Terms

CO_2 is carbon dioxide.

Carbon Capture and Storage (CCS) means capturing CO_2 from large point sources, such as fossil fuel power plants, and storing it, primarily in geologic formations, instead of releasing it into the atmosphere.

Carbon Sequestration (CS) is the term for a broader class of techniques to capture and permanently sequester, or store, CO_2 through biological, chemical, or physical processes. It includes CCS defined above.

Regional Partnership

The diversity of carbon dioxide (CO_2) sources and storage options throughout the country demands region-specific strategies. The U.S. Department of Energy has created a network of seven Regional Carbon Sequestration Partnerships to help develop the infrastructure and knowledge base needed to jump-start commercialization of CS technologies.

New York State is a member of the Midwest Regional Carbon Sequestration Partnership (MRCSP) which is composed of state agencies, universities, private companies and non-governmental organizations. The region includes New York, Ohio, Indiana, Kentucky, West Virginia, Maryland, Pennsylvania and Michigan. MRCSP is assessing carbon sequestration technologies suited to the region, identifying and evaluating appropriate storage locations, and raising awareness of CSS issues. The group is also investigating the recovery efficiencies of various CO_2 extraction and sequestration methods in an effort to reduce fuel use and lower project costs.

Work done in 2008 by the Division of Mineral Resources supported the efforts of other New York State agency members, including the New York State Energy Research and Development Authority and the New York State Museum.

New York's Potential

Once the CO_2 has been captured at its source and transported by pipeline, it would then be injected and stored safely in deep underground geologic formations located more than a half mile below the earth's surface. In New York State saline (salt-water filled) formations show the greatest promise of providing suitable underground storage sites with the ability to adequately contain the CO_2. Not all reservoirs would be suitable, however. A formation's ability to accept the CO_2 at a sufficient injection rate is one of the primary considerations when siting a potential CCS project.

The wells needed to inject CO_2 into such reservoirs would be very similar to wells the Division of Mineral Resources already regulates at underground natural gas storage facilities. Environmental protection and public safety are the Division's focus in permitting the drilling, construction and operation of underground natural gas storage wells and facilities. The same in-depth review and oversight would be required for any proposed carbon sequestration project.

Technology - Making Our Information Easy to Use

Detailed Data at Your Fingertips

Visitors to our website can easily access data on both mines and wells through our searchable databases. The mining database, which went live in 2008, can be found at http://www.dec.ny.gov/cfmx/extapps/MinedLand/ . You can search on over 20 different parameters and find information on over 3,700 mines and 1,800 mining-related companies. For the commodities parameter, choose from 30 different products to search (bluestone, sand and gravel, granite, etc.) and then further refine the search by county or town, mine name, operator name, or several other choices.

The searchable oil and gas database can be found at http://www.dec.ny.gov/cfmx/extapps/GasOil/ . Here you can search over 39,000 wells and 1,000 oil and gas producing companies. The wells data covers company, well type, permitting and drilling history, well completion, objective and producing formations, field designations, spacing status and more. Search by geologic formation, find out how much oil or gas a well has produced, and even check the transfer history of the well.

You can also see all these wells and mines on a map using Minerals Mapper at http://www.dec.ny.gov/imsmaps/minerals/viewer.htm . This interactive site allows visitors to produce maps of regulated mines and wells, along with other major geographic features such as town boundaries, roads, railways, stream and lakes, etc.

The two searchable databases and the mapping system are updated nightly, so they always provide current information.

The Division of Mineral Resources has been a strong user of technology for years. In the early 1980s the Division began computerized tracking of the wells and mines we regulate. The system initially included information just on new permits, but has expanded over the years to include more than 39,000 wells dating back to the 1800s and close to 5,700 mines in operation since the Mined Land Reclamation Law's effective date of 1975. Early data management systems for both programs were developed in-house.

Since 1998 the Division has worked with the Ground Water Protection Council (GWPC), which is a nationwide organization that includes many oil and gas producing states. The GWPC works to promote groundwater protection and also provides technical assistance to member states. One project, developed with funds from the U.S. Department of Energy, is a common database platform called a Risk Based Data Management System (RBDMS). In 2001 the Division developed a similar RBDMS-type database for the Mined Land Reclamation Program. This way both of our regulatory databases are similar in their operation and features. These databases greatly assist our oversight of the respective industries. Increased efficiency provides Division staff with faster access to and more effective use of information for permit reviews and inspections.

Other Resources on our Website

Both the Mined Land site at http://www.dec.ny.gov/lands/5020.html and Oil and Gas at http://www.dec.ny.gov/energy/205.html have extensive information for regulated parties, local governments, and the public. Both industries can find guidance and resources related to the regulatory process. The public and local governments can also use the website to learn about the Division's environmental protection requirements. Kids and teachers can find fun educational information.

The Convenience of Electronic Reporting

Since 1990 the Division has accepted electronic submission of operators' annual well reports of gas and oil production. This is a time-saving convenience both for operators and Division staff. The Division is now working toward accepting electronically submitted permit applications.

2008 New York Mined Land Reclamation Program At a Glance

Active Mines
2,166

Approx. Value
$1.3 Billion

U.S. Quantity Rank

Wollastonite	1st
Garnet	1st
Salt, Peat	3rd
Talc, Zinc	4th

Affected & Reclaimed Land

Net Affected Acreage	49,076
Life-of-Mine Acreage	119,183
Reclaimed, 2008	1,842
Reclaimed Since 1975	28,520

Common Mine Types

Sand & Gravel	1,734
Limestone	80
Bluestone	83
Sandstone	26

Financial Security
For Reclamation
$167,506,136

Owner Type

Industry	1,708
Government	458
- Local Govt.	444
- State Govt.	14

Annual Regulatory Fees
$2,837,900

Regulated Vs. Unregulated Mines

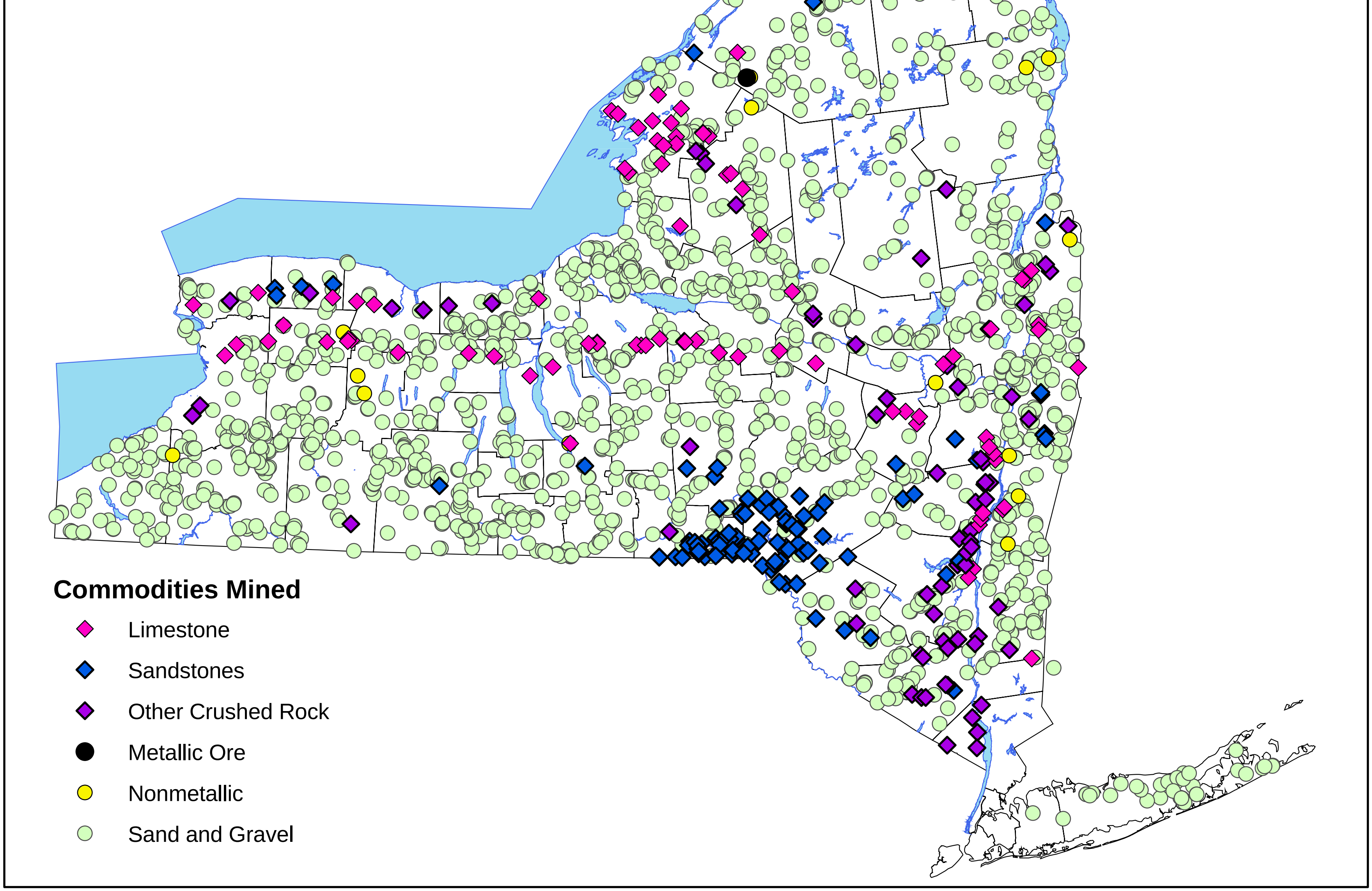
DEC's statistics in this Annual Report cover only mines regulated under the Mined Land Reclamation Law. New York also has many unregulated mines (active & abandoned) that are not under the law's jurisdiction. Most of these are small mines and/or mines that predate the 1975 law.

A permit is required under the Mined Land Reclamation Law if the following is removed:

- More than 1,000 tons or 750 cubic yards of minerals in any 12 successive months
- More than 100 cubic yards of minerals in or adjacent to any waterbody not classified as "protected" by ECL Article 15.

Lands affected by mining before 1975 and not re-affected by later mining are exempt.

Map 6 - Mines in New York State



Mined Land Reclamation Program Overview

Types of Mines in New York

In 2008 New York had 2,166 active mines. The vast majority of these mines produced sand and gravel or other surficial deposits such as glacial till, clay or topsoil. There were 286 hardrock mines producing material ranging from bluestone, limestone, shale and salt, to less common products such as wollastonite and talc. Most of New York's hardrock mines are surface quarries, but there are a few permitted underground mines.

Permits Issued in 2008

Sand and gravel mines were the most common type of mine permitted in 2008 (see Table 9). The Division issued 37 permits for new mines and 585 renewals or modifications, for a total of 622 permits (see Table 10). The high number of permit modifications in 2008 was due to DEC's decision to standardize blasting requirements statewide by modifying permits for 158 mines.

Mining permits are issued for terms of five years or less and may be renewed. A renewal permit allows continued operation of the mine within approved limits. A modification permit authorizes changes, such as addition of processing equipment or expansion of the mine's surface area or depth beyond the original approved limits. Table 12 starting on page 33 gives a more detailed breakdown of permits by county.

Table 9 - New Mines, 2008

Sand & Gravel	29
Clay	2
Dolostone, Limestone, Shale, Peat, Topsoil, Bluestone	1 each
Bluestone Exploration Authorization	7

← New Exploration Authorizations in 2008 for temporary bluestone sites that may become full-fledged permitted mines in the future.

Geographic Distribution of Mines

Map 5 on page 30 shows that mines can be found statewide; in 2008 there were active mines in 57 of New York's 62 counties. However, the map does not convey the relatively small percentage of the State's land surface devoted to mining.

The wide variation in county size means comparisons of the acreage under permit in each county can be misleading. For example, St. Lawrence, the State's largest county with an area of 1,718,848 acres, has an area 15 times larger than Rockland County. While St. Lawrence County had a relatively high total of 2,112 net affected acres under mining permit in 2008, that represented just 0.12% of the county's land. Table 11 ranks counties by the percent of their land surface under permit. It shows that mining activity is concentrated near heavily populated areas since they require larger quantities of mineral resources for roads and buildings.

In 2008 just 7 counties had more than 0.30% of their land surface under a mining permit (Albany, Dutchess, Genesee, Onondaga, Ontario, Rensselaer, Rockland) with a range of 0.30 to 0.41%. For most of the counties with active mines, less than 0.25% of their land was affected.

Table 10 - Permits, 2004 - 2008

	2004	2005	2006	2007	2008
New Permits	55	66	47	46	37
Renewals & Modifications	420	345	327	326	585*
Total Permits	475	411	374	372	622

*158 permit modifications were initiated by DEC to standardize blasting requirements.

Owner Type

In 2008 industry operated 1,708 mines or slightly over three-fourths of the mines in New York State.

In 2008 there were 49 county-owned mines and 395 belonging to towns, villages and other small local government entities. New York State agencies also operate 14 mines. Most of the government mines belong to highway departments which use the material for road maintenance.

In addition to owning roughly one-fifth of the mines in New York State, government agencies at all levels purchase significant quantities of sand, gravel and other aggregates from commercial mines.

Annual Regulatory Fees

In 2008 the Division collected $2,837,900 in annual regulatory fees. Acreage-based fees are collected for individual, industry and state-owned mines. County, town, village and other local government mines are exempt. The fees support the mined land regulatory program. Database enhancements now allow staff to more closely monitor payment histories, review compliance, and conduct fee enforcement.

Mine Ownership

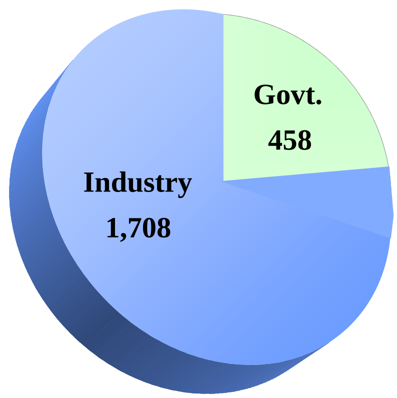


Table 11 - Counties with Highest Percentage of Land Under Mining Permit, 2008

County	Population Ctr. Nearby	Active Mines	Net Affected Acreage	Land Percent
Genesee	Buffalo	24	1,319	0.41%
Rensselaer	Capital/Tri-City	60	1,706	0.40%
Onondaga	Syracuse	41	1,991	0.39%
Ontario	Rochester	43	1,550	0.37%
Albany	Capital/Tri-City	18	1,210	0.35%
Rockland	New York City	4	433	0.34%
Dutchess	New York City	58	1,643	0.31%
Saratoga	Capital/Tri-City	62	1,591	0.29%

Table 12 - Number of Permits and Acreage by County, 2008

	2008 New Permits[1]		Total Permits[1]	
County	Number	Acres[2]	Number	Acres[2]
Albany	0	0	18	1,211
Allegany	2	13	39	377
Broome	1	24	45	747
Cattaraugus	0	0	70	1,636
Cayuga	1	5	22	363
Chautauqua	1	2	55	448
Chemung	1	5	26	414
Chenango	1	4	38	693
Clinton	1	5	67	1,243
Columbia	0	0	37	1,001
Cortland	0	0	18	326
Delaware	1	7	69	809
Dutchess	1	7	58	1,643
Erie	3	18	52	1,981

	2008 New Permits[1]		Total Permits[1]	
County	Number	Acres[2]	Number	Acres[2]
Essex	0	0	41	726
Franklin	3	20	73	686
Fulton	0	0	24	375
Genesee	1	5	24	1,319
Greene	0	0	23	1,022
Hamilton	0	0	21	142
Herkimer	0	0	49	1,298
Jefferson	0	0	78	1,857
Lewis	4	32	45	692
Livingston	0	0	23	992[3]
Madison	1	5	25	542
Monroe	0	0	12	570
Montgomery	0	0	8	564
Nassau	1	4	1	4

1 Regulated mines, but not bluestone exploration authorizations
2 Net affected acreage
3 Does not include underground acreage for salt mines
Livingston 603 acres, Tompkins and Seneca 9,000 acres

Table 12 - Number of Permits and Acreage by County, 2008 (continued)

County	2008 New Permits[1]		Total Permits[1]	
	Number	Acres[2]	Number	Acres[2]
Niagara	0	0	16	703
Oneida	0	0	64	1,149
Onondaga	1	10	41	1,991
Ontario	0	0	43	1,551
Orange	0	0	44	789
Orleans	0	0	20	547
Oswego	1	10	106	1,638
Otsego	0	0	36	545
Putnam	0	0	3	68
Rensselaer	3	9	60	1706
Rockland	0	0	4	433
Saratoga	1	3	62	1,591
Schenectady	0	0	9	238
Schoharie	0	0	17	520
Schuyler	0	0	12	274

County	2008 New Permits[1]		Total Permits[1]	
	Number	Acres[2]	Number	Acres[2]
Seneca	0	0	5	358[3]
St. Lawrence	1	5	105	2,112
Steuben	1	31	84	1,940
Suffolk	1	7	36	1,123
Sullivan	1	5	31	1,021
Tioga	1	16	32	825
Tompkins	0	0	15	508[3]
Ulster	0	0	49	832
Warren	0	0	36	570
Washington	0	0	57	873
Wayne	2	18	42	1,013
Westchester	0	0	1	4
Wyoming	2	10	27	208
Yates	0	0	13	161

1 Regulated mines, but not bluestone exploration authorizations

2 Net affected acreage

3 Does not include underground acreage for salt mines
Livingston 603 acres, Tompkins and Seneca 9,000 acres

Trends in Mine Size and Number

Mine renewal and modification permits issued in 2008 ranged in size from 1 to 839 acres. However, new mines tend to be smaller; 85 percent of new mines permitted in 2008 were 10 acres or less in size. The largest new mine was the 68-acre Presho Sand & Gravel Mine in Steuben County.

Table 13 gives 2003-2008 size range information for all active mines. The number of large mines has been increasing over time, while the number of small mines has been decreasing. This is because many operators are expanding or combining existing mines rather than seeking permits for new ones.

The minor projects in the first row of the table are always less than 5 acres in size. They are subject to a simpler review process, but must comply with very strict criteria to be considered minor: minimum setbacks from homes and surface waters; a maximum 20-foot mine depth; no mining below water table; no hardrock (consolidated material) mining; and no on-site processing equipment, such as washing or crushing machines.

Mine Acreage Types and Statistics

Net Affected Acreage - Net affected acreage is the total affected acreage covered under successive mined land permits for the site minus the acreage reclaimed over the years. In 2008 the total affected land authorized for mineral extraction under current mined land reclamation permits was 49,076 acres.

Life-of-Mine Acreage - This is the total area that has been subject to DEC's environmental review. It covers acreage mined under past permits, the current permit, and acreage that the operator intends to mine under future permits. It also includes all reclaimed acreage at the site. In 2008 the statewide total for life-of-mine area was 119,183 acres.

Reclaimed Acres - In 2008 the Division approved final reclamation of 637 acres at 74 closed mines and concurrent reclamation of 1,205 acres at 97 operating mines. Table 14 on page 38 summarizes 2008 reclamation by county. Since 1975 a total of 28,520 acres of mined land have been reclaimed, including 1,842 acres reclaimed in 2008.

Table 13 - Range of Existing Mine Sizes, 2003 - 2008*

	2003	2004	2005	2006	2007	2008
Minor Projects	80	78	81	80	88	69
0 to 5 Acres	751	712	683	652	651	636
>5 to 10 Acres	549	532	531	531	509	493
>10 to 20 Acres	446	442	439	439	431	437
>20 to 30 Acres	172	179	179	169	166	171
>30 Acres	319	329	336	344	358	360
Total Mines	2,317	2,272	2,249	2,215	2,203	2,166

* Net Affected Acres

Reclamation and Financial Security

Reclaimed Land Uses

Final uses of mined land can vary considerably depending on location, size and depth of the site; surrounding land uses; and local zoning. Farmland and pasture are two of the most common reclamation objectives in New York State, but mined land is also reclaimed to residential, forestry, wildlife, recreational, commercial and industrial uses. Once the Division permits a proposed reclamation objective in a mined land reclamation plan, the mine operator needs a permit modification to change it.

Reclamation takes two forms based on timing of the work - concurrent or final. Concurrent reclamation is reclamation of an affected or mined-out area while resources are still being extracted from other parts of the mine site.

The Division strongly promotes concurrent reclamation, particularly for mines over 10 acres in size. Concurrent reclamation has a number of advantages. Chief among these are the reduced potential for negative environmental impacts (dust, erosion, sedimentation) and the improved perception of the mine by the surrounding community. See Table 14 on page 38 for a breakdown of reclamation type by county.

Financial Security

Municipal and other government operations are exempt from financial security requirements. However, mine operators from the private sector are required to post financial security to guarantee reclamation of their mines. At the end of 2008 the Division held roughly $167.5 million in financial security, an increase of $28 million from 2007.

In the rare case where a mine operator fails to reclaim a mine, the Division calls the financial security and reclaims the land. However, staff noted that bonding levels were not keeping pace with rising reclamation costs. In 2006 the Division studied the issue and adopted a more detailed system of assessing reclamation costs. Since 2006 the Division has used the new methodology to calculate the required bonds for all new permits, permit renewals, modifications and transfers. Reclamation estimates completed in 2008 averaged $4,638 per acre. As more permits come up for renewal, the statewide average is expected to rise to $5,000-$6,000 per acre over the next few years.

DEC Reclamation of Abandoned Mines

In 2008 DEC Region 7 Division of Operations staff completed reclamation of the PA Stone Store Sanford Quarry in the Town of Sanford, Broome County. The mine was reclaimed using $10,000 in financial security seized by the Division of Mineral Resources. The poor condition of the haul road made the site practically inaccessible to motorized vehicles and required significant work before reclamation could proceed. Operations staff started the reclamation project in 2007 and returned to the site to hydroseed and mulch the affected areas in 2008.

Region 7 DEC Operations staff reclaiming a mine with financial security funds seized by the Mined Land Program.

In 2008 Region 7 Operations staff also completed reclamation of the abandoned James Kolba-Kline Mine in the Town of Barker, Broome County. DEC seized the mine operator's $20,000 in

financial security in 1994. In 2001 Central Office Mined Land staff surveyed the site and prepared a reclamation work plan and cost estimate. However, for various legal reasons the site remained unreclaimed. In 2008 Mined Land staff were finally able to bring the problem to a successful conclusion. A site meeting was held to discuss the project among Central Office and Region 7 Mined Land Staff, Region 7 Division of Operations staff and the landowner. Inspection of the site revealed that a significant portion of the land had revegetated naturally and was stable. While this is a rare occurrence, it reduced the size of the area that needed reclamation to only 3.5 acres. Central Office staff developed a revised work plan and determined that the $20,000 available would be adequate to cover costs. The work was completed in October 2008.

R.T. Vanderbilt Talc Mine No.2 in the Town of Fowler, St. Lawrence County

2008 Reclamation Highlights

The R.T. Vanderbilt Company decided to close its talc/tremolite mines in St. Lawrence County in 2008. The closure requires reclamation of the Vanderbilt open pit mines located in the Towns of Fowler and Edwards. Region 6 Mined Land Staff conducted inspections throughout 2008 and found progress satisfactory. The company estimated that it will take a total of 6,000 hours of work to complete the necessary reclamation activities.

For many years New York State ranked fourth in the nation in talc production. Talc/tremolite is used primarily in making paint and ceramics. The first talc mine in the United States opened in 1878 on a farm near Talcville, which is in the same area as the mines that are now being reclaimed.

In 2008 work continued on Maya Lin's Wavefield Landform at the Storm King Art Center (SKAC) in Orange County. DEC approved this site-specific earthwork as an acceptable reclamation use of a former gravel pit on the grounds of the outdoor sculpture park. SKAC is home to more than 100 works by world-renowned artists.

In October Region 3 staff met with the contractor and landscape architect to review minor work that needed to be completed prior to a photo shoot for a *New York Times* article that was published in November 2008.

Work began on constructing the wavefield in 2007. It consists of 12- to 18-foot high "earthen swells" in seven rows, each over 300 feet long. The undulating hills give the appearance of ocean waves that visitors can walk into. The hills were planted with native grasses and scheduled to open to the public in 2009, once the vegetation is sufficiently established.

The Wavefield near completion October 2008; the "waves" are 12 to 18 feet high.

Table 14 - Reclamation Acreage Summary by County[1], 2008

County	Concurrent	Final	Total
Albany	5.2	0	5.2
Allegany	15.2	52.1	67.3
Broome	23.2	107	130.2
Cattaraugus	373.2	13	386.2
Cayuga	0	26	26
Chautauqua	2.7	3	5.7
Chemung	10	0	10
Chenango	0	5	5
Clinton	9.8	3.3	13.1
Columbia	14.2	13	27.2
Cortland	40.2	8	48.2
Delaware	0	27	27
Dutchess	92	4	96
Erie	45.8	2	47.8
Essex	0	0	0
Franklin	8	3	11
Fulton	7.2	0	7.2
Genesee	4	0	4
Greene	8.7	0	8.7
Hamilton	0	4.3	4.3
Herkimer	10	2	12
Jefferson	17.3	10.7	28
Lewis	0	7	7
Livingston	0	23.1	23.1
Madison	0	0	0
Monroe	125	65	190
Montgomery	0	0	0
Niagara	66.5	0	66.5
Nassau	0	0	0
Oneida	21.8	12	33.8
Onondaga	29	6.3	35.3
Ontario	18.3	22	40.3
Orange	4.5	47.5	52
Orleans	3	0	3
Oswego	4	0	4
Otsego	9.6	22.6	32.2
Putnam	0	2	2
Rensselaer	15.4	23	38.4
Rockland	0	0	0
Saratoga	60.8	5	65.8
Schenectady	0	0	0
Schoharie	0	0	0
Schuyler	0	0	0
Seneca	0	0	0
St. Lawrence	41.3	11.4	52.7
Steuben	75.8	19.1	94.9
Suffolk	2	2.1	4.1
Sullivan	10	0	10
Tioga	0	17	17
Tompkins	0	0	0
Ulster	13.5	54	67.5
Warren	0	0	0
Washington	18	9.1	27.1
Wayne	0	6	6
Westchester	0	0	0
Wyoming	0	0	0
Yates	0	0	0

[1] Five counties that do not have DEC–regulated mines are not included in this table.

Compliance and Enforcement

Inspections

In 2008 Mined Land staff performed 2,417 mine inspections and traveled 89,964 miles. Staff inspect mine sites:

- during permit application review;
- during operation for general compliance;
- to ensure that violations are remediated;
- to ensure that reclamation meets requirements; and
- to investigate complaints.

Violations and Fines

Violations are handled with a mixture of enforcement tools, remediation requirements and penalties. In 2008 the Mined Land Program collected $815,600 in fines and penalties for 44 cases.

Significant Legal Cases

In October 2007 Region 1 Mined Land staff discovered that 60,000 cubic yards of material had been illegally removed from the buffer area of a mine in the community of Kings Park, Town of Smithstown, Suffolk County. In 2008 a penalty of $275,000 was assessed against the permittee. In addition, the operator must reclaim the affected area.

Region 1 Mined Land staff discovered that a mine in the Town of Brookhaven, Suffolk County, had been extended outside of the approved life-of-mine limits. The permittee agreed to a $400,000 penalty, with $100,000 payable and $300,000 suspended if no further violations occur at the mine. The mineral resources at the site are exhausted and reclamation is required.

Region 1 staff aided an Assistant Attorney General in preparing an affidavit opposing a request from the Town of Riverhead for a Temporary Restraining Order in the Island Water Park case. The company requested a permit modification to create two lakes for water skiing when the mine is reclaimed. This would be a significant change from the original plan approved in the permit. The Town of Riverhead requested lead agency status, but the Commissioner granted it to DEC, so the Town tried other legal measures to stop the review process.

At year-end 2008 Region 3 staff were negotiating a settlement with an operator over violations at mines in Dutchess and Rockland counties. At the Dutchess County site, broken slurry lines released sediment-laden water into the Hudson River. At the Rockland County mine there were also several violations associated with relocation of the settling ponds and primary crusher. The company overexcavated 26,000 cubic yards of material from the new crusher location. Numerous SPDES violations resulted in turbidity in the Hackensack River and disruption of the Village of Nyack water supply.

For over 20 years Region 6 has been involved with a landowner in the Town of Lawrence, St. Lawrence County for various violations including illegal mining and operating a solid waste facility without a permit. Several times in the past, cases brought against the landowner were either dismissed by local courts or very minor penalties were imposed. The most recent trial was finally convened in 2008, three and a half years after a search warrant was executed to gather evidence to confirm aerial surveillance. In the interim there were several adjournments, two failed attempts to seat a jury, and a change in venue.

Since several previous administrative actions had failed to resolve the violations at the site, this time Region 6 sought criminal charges. The landowner was charged with mining without a permit, operating a solid waste facility without a permit, and three additional solid waste violations. Unfortunately, during the trial the Assistant District Attorney was unable to have some important aerial photography entered into evidence. Subsequently, the landowner was found guilty of the solid waste violations, but not of mining without a permit.

2008 Mined Land Reclamation Program Highlights

Economic Assessment of NY Mining Industry

At the Fall 2008 New York Construction Materials Association meeting, Dr. Rochelle Ruffert of the Center for Governmental Research and Dr. William Kelly of the New York State Geological Survey presented the preliminary results of a study on the economic impacts of mining in New York State.

The latest U.S. Geological Survey estimate of the value of minerals produced in New York is $1.3 billion. However, in this more detailed study, responses from just 91 survey participants showed an estimated economic impact from the mining industry of $1.5 billion. Extrapolating this figure to include all permitted mines in the State, including indirect and multiplier effects, would yield an economic impact of several billion dollars. After the meeting Division staff provided Dr. Ruffert with additional information on active mines in the State.

Annual Underground Salt Mine Inspections

Department staff and a Geomechanics Specialist from John T. Boyd Company conducted the annual underground mine inspections of the American Rock Salt (ARS) Hampton Corners salt mine and the Cargill (Cargill) Cayuga salt mine. The State Geologist was also present at the inspections. Permit conditions require these detailed annual inspections to ensure DEC is aware of any potential problems.

During the site visits staff inspected the entries, crosscuts, faces, data collection points, and process galleries. At ARS all openings were stable and there was no sign of water flowing into the mine. At the Cargill site, a mine “panel” that had previously shown increased convergence rates was checked again, but no further deterioration was noted and the area was being backfilled.

For years New York has ranked third in the nation in salt production, based on the combined total of mined and solution-mined salt.

Adirondack Rock Fest

Central Office staff represented the Division at the first annual Rock Fest: A Celebration of Adirondack Geology. The event was held at the Adirondack Park Agency’s Newcomb Visitor Interpretive Center (VIC) on August 9. It was sponsored by VIC and the SUNY College of Environmental Science and Forestry Adirondack Ecological Center.

The event consisted of a series of presentations both at the VIC and at nearby rock outcrops, followed by a field trip to the old titanium mine at Tahawus. Division staff made a presentation on the everyday uses of minerals and gave an overview of the Mined Land Reclamation Program. Division members also staffed a display and answered many questions.

The program was quite successful for a first-time event. Over 100 people attended and at least 65 people went to each of the presentations.

NYCO Examines Wollastonite Options

A meeting was held on October 29, 2008, at the NYCO Minerals Willsboro office in Essex County. NYCO gave a presentation on depletion of wollastonite reserves at its two active quarries in the Town of Lewis; one mine is expected to be depleted in 5 years and the other in 20 years. New York State is home to the only commercial wollastonite production in the country.

When its New York reserves are exhausted, NYCO could rely solely on its large wollastonite mine in Mexico. However to avoid terminating its New York operations, NYCO is attempting to locate additional reserves. The possible acquisition of State Forest Preserve Lot #8, which adjoins the Lewis Quarry, is one option. Since Article 14 of the New York State Constitution prohibits the mining or exploration of State Forest Preserve lands, a constitutional amendment would be required to pursue this option.

Zinc Mine Closes Again

St. Lawrence Zinc, a subsidiary of HudBay Minerals, announced the closure of the Balmat underground zinc mine in the Town of Fowler, St. Lawrence County. Rising fuel costs and a steep drop in the price for zinc concentrate led to the decision.

For many years New York State ranked third or fourth in the country in zinc production. However, the mine has periodically closed and reopened over the last few years with fluctuating zinc prices. In April 2001 the Zinc Corporation of America closed the mine after zinc prices fell to 32 cents per pound. In April 2006 HudBay Minerals reopened the mine after zinc prices soared to a record of over $2.00 per pound. However, in 2008 fuel prices rose significantly and zinc prices fell to around 70 cents per pound, necessitating closure of the mine.

Human Remains Identified at Mine

In February 2008 human remains were discovered during mining operations at the Full Cycle Soils mine in the Town of Phelps, Ontario County. Initially, the Ontario County Sheriff's Department and Ontario County Medical Examiner thought the bones were of recent origin. However, the skeletal remains were sent to a forensics anthropologist who determined that they were probably from two people, not one, and may have been from a Native American woman and her infant. The mine suspended operations until the NY State Office of Parks, Recreation, and Historic Preservation could make a determination whether additional investigation was necessary.

TCE-Contaminated Water at Mine

Dolomite Products submitted an application for the discharge of trichloroethylene (TCE)-contaminated water from the Leroy Quarry in Genesee County. The mine is not the cause of the contamination; TCE was spilled during an accident on the Lehigh Vallley Railroad in 1970 and has slowly migrated underneath the mine. Fortunately, the level of contamination has continued to drop over the decades.

Regional and Central Office staff met with the company to discuss the application for a State Pollutant Discharge Elimination System (SPDES) permit and DEC's concerns about the treatment and discharge plans. Staff review continues and a Draft Environmental Impact Statement is anticipated.

R.T. Vanderbilt Closing Three of Four Mines

R.T. Vanderbilt Company announced the closure of its two talc/tremolite mines in Balmat and one in Talcville, all in St. Lawrence County. A drop in market demand from over 200,000 tons per year in 1988 to around 80,000 tons in recent years led to the decision. The company plans to continue a small wollastonite mine in the Town of Diana, Lewis County. In 2008 roughly 105 people were employed at the company's Balmat mines and mills. See the reclamation section on page 37 for further information.

Bluestone Expo 2008

Central Office and Region 7 Mined Land staff attended the Bluestone Expo 2008 held March 29-30 in Binghamton, Broome County. The event was a joint effort of the New York and Pennsylvania bluestone industry organizations. Regulators, vendors, consultants, and financial institutions were present to answer questions and receive feedback from participants.

Division members staffed a display and interacted with the bluestone community. Attendance was down from the first Bluestone Expo in 2006, probably due to the economic conditions.

Mine Replaces Diesel Equipment

At the 154-acre Troy Sand and Gravel Mine in the Town of West Sand Lake, Rensselaer County, the company converted several major pieces of equipment from diesel power to natural gas and electricity. The company produces stone, sand and gravel at this site and also manufactures asphalt. The 1,000-watt diesel generator used for stone processing was changed to natural gas.

Diesel fuel used in drying and heating stone was also replaced by natural gas. In addition to making the operations at the site more energy efficient, the conversions were expected to reduce noise, odor, and air pollution.

Three Mine Fatalities in May 2008

The Division of Mineral Resources continues to support the work of the U.S. Mine Safety and Health Administration (MSHA) in their "Stay Out – Stay Alive" campaign. The program is aimed at educating children and adults about the dangers of trespassing on mine property for recreational purposes. Division staff distribute MSHA's educational materials at outreach events.

There continues to be a need for this type of information. In 2008 an 18-year old man died when he was camping out with friends in the inactive part of a limestone mine in Greene County. Also during 2008 workers at two different mines in northern New York were killed. One was a dozer operator constructing a new ramp at a mine in Jefferson County who was crushed under his equipment. The other fatality was in Saint Lawrence County when a man working in an underground mine was killed by a falling slab of rock. MSHA investigated all three deaths.

Former Mine Site Reclaimed to Farm Pond,

Town of Redhook, Dutchess County

DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF OIL AND GAS MANAGEMENT

DOCUMENT NUMBER: 550-0800-001

TITLE: Pennsylvania's Plan for Addressing Problem Abandoned Wells and Orphaned Wells

EFFECTIVE DATE: April 10, 2000

AUTHORITY:

The Oil and Gas Act (P.L. 1140, No. 223) (58 P.S. Section 601.101 et seq.)
Coal and Gas Resource Coordination Act (P.L. 1069, No. 214) (58 P.S. Section 501.1 et seq.)
Oil and Gas Conservation Law (P.L. 825, No. 359) (58 P.S. Section 401.1 et seq.)
The Clean Streams Law (P.L. 1987, No. 394) (35 P.S. Section 691.1 et seq.)
Solid Waste Management Act (P.L. 380, No. 97) (35 P.S. Section 6018.101 et seq.)
The Administrative Code (P.L. 177, No. 175) (71 P.S. Section 510-1 et seq.)
25 Pa. Code Chapters: 78, 79, 91, 95, 97, 101, 102, 105, 106, 260, 261, 287, 288, 289, 291, 293, and 299

POLICY:

DEP will follow the strategy explained in this document when deciding which abandoned oil and gas wells to plug under contract.

PURPOSE:

This guidance document provides the Department's rationale in determining the optimal use of funds, including Growing Greener funding, available for plugging abandoned wells under contract. The strategy is to be incorporated into the state's Reclaim PA initiative.

APPLICABILITY:

These policies apply as guidance for decisions by DEP's oil and gas management program when determining which abandoned wells to plug, and when.

DISCLAIMER:

The policies and procedures outlined in this guidance document are intended to supplement existing requirements. Nothing in the policies or procedures shall affect regulatory requirements.

The policies and procedures herein are not an adjudication or regulation. There is no intent on the part of the Department to give these rules that weight or deference. This document establishes the framework within which DEP will exercise its administrative discretion in the future. DEP reserves the discretion to deviate from this policy statement if circumstances warrant.

LENGTH: 7 pages

LOCATION: Volume 11, Tab (05)

Department of Environmental Protection
Bureau of Oil and Gas Management

2000

Pennsylvania's Plan For Addressing Problem Abandoned Wells and Orphaned Wells

Table of Contents

I. Introduction

The first commercial oil well was drilled near Titusville in 1859. However, plugging requirements designed to protect oil producing formations from flooding by fresh water were not enacted by the Legislature until the 1890s. Legislation passed in 1921 specified methods for pulling casing and plugging wells. It was not until 1956 that legislation required gas wells to be permitted so their locations could be coordinated with underground coal mining to assure the safety of coal miners. The same legislation was amended in the early 1960s to require all oil and gas wells to be permitted. These initial permits were registrations of locations where well drilling was being considered.

In the early 1980s more comprehensive oil and gas legislation was enacted. In December 1984 the Oil and Gas Act was signed into law. The Act defined an abandoned well as any well that had not been produced by its operator in the last year or any well that was not completed for production within 60 days of having been drilled. Excluded from this category were any wells that had been granted inactive status by the Department. This statute provided for, among other things, an Abandoned Well Restricted Revenue Account and the registration of wells drilled prior to the permitting requirements. The Abandoned Well Restricted Revenue Account was to be used by the Department of Environmental Protection (DEP) to plug abandoned wells causing health, safety, or environmental problems, and for carrying out other purposes of the Act. This fund received revenues from fines, fees, penalties, and from a $50.00 surcharge on all oil and gas well drilling permits.

In the 140 years since the first oil well was drilled, an unknown number of oil and gas wells have been drilled in Pennsylvania. An estimate by the Independent Petroleum Association of America places that number at approximately 325,000. DEP has records of 88,300 operating wells which it regulates, 44,700 plugged wells, and approximately 8,000 orphaned and abandoned wells. The status of the remaining 184,000 wells is unknown. Many wells were drilled, operated, and plugged at the end of their useful life while others were drilled, operated and abandoned without proper plugging. Some wells were “temporarily abandoned” while the operators waited for the price of oil to rise to a level which would make producing the wells profitable; this sometimes never occurred.

With the passage of the well registration requirements of the Oil and Gas Act, questions arose concerning plugging liability for wells that were abandoned years ago by prior, often unidentified, operators. Consequently, in 1992 the Legislature amended the Act to establish an Orphan Well Plugging Program. Orphaned wells are a subclass of abandoned wells. Orphaned wells are wells that were abandoned prior to April 18, 1985. They have not been affected or operated by the present owner or operator and the present owner, operator or lessee has received no economic benefit. If DEP determines that a prior owner or operator received economic benefit, other than economic benefit derived as a landowner or from a royalty interest subsequent to April 18, 1979 from an orphaned well or from a well which has not been registered, that owner or operator is responsible for plugging the well. The Orphan Well Plugging Program receives revenues from industry through a $100.00 surcharge on new oil well permit fees and a $200.00 surcharge on new gas well permit fees. The Orphan Well

Plugging Fund is separate from, and in addition to, the Abandoned Well Plugging Fund which was established with the $50 surcharge from the Abandoned Well Restricted Revenue Account of 1984.

The Oil and Gas Act authorizes DEP to plug abandoned oil and gas wells. The main focus to date has been the plugging of wells which were clearly showing hazards to public health and safety and/or environmental degradation particularly to water supplies. A ranking system for abandoned wells, based on threats to health and safety or pollution of the waters of the Commonwealth, is currently in use. A similar ranking system for orphaned wells is based on whether the well is on public or private land; its distance from public or private water supplies, accessible areas or buildings; its distance from streams, bodies of water, or wetlands; and whether or not it is in a special protection watershed. Revenues from surcharges into the Abandoned Well Plugging Fund and the Orphan Well Plugging Fund total approximately $300,000 a year.

Since the well plugging program began, 108 wells have been plugged at a cost of over $2.4 million using funds from the Abandoned Well Plugging Fund, the Orphaned Well Plugging Fund, and a Federal Clean Water Act, Section 319 Non-Point Source (319 NPS) grant. The wells plugged under the 319 NPS grant were plugged to halt discharges of acid mine drainage and improve stream quality in the Mill Creek Watershed and stop oil migration in the Oil Creek Watershed.

On December 15, 1999, Governor Thomas Ridge signed the Growing Greener legislation. This represents the largest single investment of state funds in Pennsylvania history to address critical environmental concerns such as abandoned and orphan wells. Approximately $3 million dollars a year of Growing Greener funding will go towards plugging wells from 2000 to 2004. Initial Growing Greener grant dedications include $280,000 funded the plugging of 79 wells in McKean County, $20,000 towards one well in Allegheny County, and $213,180 for 50 wells in Warren County. These examples demonstrate how Growing Greener is helping Pennsylvania's plan to plug abandoned and orphaned wells.

The Environmental Protection Agency (EPA) has also plugged over 190 abandoned wells in Pennsylvania that were leaking oil, or threatening to leak oil, to the navigable waters of the United States. The well plugging was made possible using funds from the Federal Oil Spill Liability Trust Fund (OSLTF) that was established under the Oil Pollution Act of 1990 (OPA 90).

II. Purpose for This Plan

The purpose of this plan is to establish the direction of DEP well plugging activities.

III. Guiding Principles

In developing and implementing a comprehensive plan for addressing problem abandoned wells and orphaned wells, state and federal resources should be coordinated to ensure cost-effective results. The following set of principles is intended to guide decision-making.

- Priority will be given to problem wells that threaten the health and safety of people or property or pollution of the waters of the Commonwealth.

- Partnerships between DEP, the Department of Conservation and Natural Resources (DCNR), other state and federal agencies, and watershed associations will be established, when appropriate, to achieve cleanup of a defined geographical area in an efficient and effective manner.

- Where practical, plugging activities will be coordinated with other projects that involve a watershed or geographic area where environmental cleanup and restoration efforts are planned or in progress. This coordination would occur as part of the Reclaim PA initiative.

- Consideration will be given to plugging projects where arrangements for utilization of money from federal and other sources, such as the OSLTF, or 319 NPS grants, exist or can be developed.

- Adoption of problem abandoned wells or orphaned wells that have production potential will be encouraged so that the oil and gas resources are conserved.

- Problem abandoned wells and orphaned wells will continue to be documented and added to the inventories as they are identified.

IV. Goals

Specific goals to be achieved are set forth below. These goals are to be reviewed, modified, expanded, or changed when necessary to ensure the goals meet the needs of the time.

A. Focus expenditures for plugging problem abandoned wells on those which threaten the health and safety of persons or property or pollution of the waters of the Commonwealth.

Of the approximately 8,000 unplugged orphaned wells, 550 are considered problem wells. Of the 550 problem wells, approximately 129 are prioritized at 30 points or more. Our goal is to give these 129 wells high priority for plugging.

B. Develop partnerships with the federal government, DCNR, watershed associations, local governments, and other groups that promote locating and plugging problem abandoned and orphaned wells.

DEP completed a 319 NPS three well plugging contract in Mill Creek Watershed to improve stream quality. These wells were brought to the attention of DEP by the Mill Creek Coalition as being the source of acid mine drainage into Mill Creek. Seven other wells discharging oil, or threatening to discharge oil, into Oil Creek were plugged under the same 319 NPS grant. DEP will continue to foster additional cooperative partnerships with governmental or other watershed groups.

C. Develop an areal approach to planning plugging operations that will result in reclamation and rehabilitation of an entire geographical area or watershed.

DEP's goal during the next five years is to contract for plugging clusters of wells in defined geographic areas. The key well in each well cluster contract will be a problem abandoned well with high priority points. When the key well or wells are identified, the abandoned and orphaned well lists will be examined to determine what other wells are located in the same geographic area. Once these wells are identified, they will be included in a cluster well plugging contract.

D. Encourage adoption of problem abandoned wells and orphaned wells.

DEP is providing oil and gas operators lists of abandoned wells in the database. The oil and gas operators can determine whether it is economically beneficial to them to adopt the well and return it to production, rather than have DEP plug the well and loose a potential resource. Our goal is to continue to make oil and gas operators aware of the opportunities to adopt orphaned oil and gas wells and to return them to production.

V. Plan Elements

A. Focusing of Expenditures

DEP maintains an inventory of problem abandoned and orphaned wells. This inventory is also in a database format. Prioritized lists of problem abandoned and orphaned wells are generated from this database. These prioritized lists aid in selecting wells for plugging.

These prioritization lists are being used to focus plugging expenditures on the 129 high priority wells.

B. Developing Partnerships

Currently DEP uses funds from the Abandoned Well Plugging Fund to plug problem abandoned wells, and funds from the Orphan Well Plugging Fund to plug orphaned wells. Abandoned wells that are an immediate threat to the health and safety of people or property or pollution of the waters of the Commonwealth are plugged by DEP through emergency response action. Abandoned wells that discharge or threaten to discharge oil into navigable waters of the United States are eligible to be plugged by DEP or EPA using funds from the Oil Spill Liability Trust Fund (OSLTF) established under the Oil Pollution Act 90. EPA is currently plugging these types of wells using funds from this source.

Contacts between DEP and EPA have been established to coordinate activities for plugging problem abandoned wells. This will ensure that the respective agencies will not duplicate efforts by both trying to plug the same wells at the same time.

Problem abandoned wells that had been leaking oil and were previously plugged by DEP will be examined to determine their eligibility for reimbursement of plugging costs under the OSLTF. Claims for reimbursement will be submitted to the OSLTF.

Contacts have been made with DCNR to enter into a cost sharing partnership to plug orphaned wells on property owned by DCNR. Approximately 100 orphaned wells fall within this category.

Contacts have been made with the Mill Creek Coalition, the Pine Creek Headwater Protection Group, and The Scott Conservancy to determine if abandoned wells are contributing to the pollution of watershed areas the associations are trying to clean up.

Contacts have been made with the United States Forest Service to access orphaned wells located in the Allegheny National Forest.

C. An Areal Approach to Well Plugging

DEP will group problem abandoned and orphaned wells by municipalities, watersheds, geographic boundaries, or surface landowners to more efficiently address the plugging of these wells. This will facilitate a cluster well plugging program that will result in the restoration of an entire area rather than scattered sites, and decrease per well plugging costs.

The key well in the cluster will be a well that has a high priority. When these problem wells are plugged, they will be grouped into clusters with other orphaned wells in the area. When possible, 50 to 100 wells or more will be grouped together into single contracts. It is expected that clustering wells into contracts will increase program efficiency.

D. Encouraging Adoption

DEP will periodically remind the oil and gas industry of the availability for adoption of orphaned and abandoned wells on our plugging lists. DEP will do this by placing articles in the Update and by positing information on the web site.

Upon request, DEP will provide a list of orphaned and abandoned wells to anyone who requests such information for the purpose of adoption.

Oversight Hearing before the Subcommittee on Energy and Mineral Resources of the On Natural Resources US House of Representatives, One Hundred Eleventh Congress, First Session (Serial No. 111-22)
June 4, 2009
Representative Doug Lamborn of Colorado
"Hydraulic fracturing has been used by the oil and gas industry since the late 1940s. More than one million fracturing jobs have been completed in the U.S. since the technique was first developed, and there have been no demonstrated adverse impacts to drinking water wells from the fracking process or by the fluids used in the process."
Source: http://www.gpo.gov/fdsys/pkg/CHRG-111hhrg50120/pdf/CHRG-111hhrg50120.pdf

Oversight Hearing before the Subcommittee on Energy and Mineral Resources of the On Natural Resources US House of Representatives, One Hundred Eleventh Congress, First Session (Serial No. 111-22)
June 4, 2009
Lynn Helms, speaking as Director, Department of Mineral Resources, Industrial Commission, State of North Dakota
"Studies and surveys by GWPC, EPA and IOGCC over the last 11 years have found no real credible threat to underground drinking water from hydraulic fracturing. It is a common operation used in North Dakota and all the member states of the IOGCC, and it is my firmly held view and also that of IOGCC that the subject of hydraulic fracturing is adequately regulated by the states, and it needs no further study."
"In a 1998 survey of state oil and gas regulatory agencies, conducted by the GWPC, twenty four state programs said they had not recorded any complaints of contamination to a USDW that the agency could attribute to hydraulic fracturing of coalbed methane zones.
In 2004 the Environmental Protection Agency published a final report summarizing a study to evaluate the potential threat to underground sources of drinking water from hydraulic fracturing of coal bed methane production wells and the Environmental Protection Agency concluded that 'additional or further study is not warranted at this time...' and that 'the injection of hydraulic fracturing fluids into coal bed methane wells poses minimal threat to the underground sources of drinking water'.
Subsequently, the IOGCC conducted a survey of North Dakota and other oil and gas-producing states that found that there were no known cases of ground water contamination associated with hydraulic fracturing. Hydraulic fracturing is a common operation used in exploration and production by the oil and gas industry in North Dakota and all the member states of the IOGCC. Approximately 35,000 wells are hydraulically fractured annually in the United States, and close to one million wells have been hydraulically fractured in the United States since the technique's inception, with no known harm to ground water.
It is my firmly held view and that of the IOGCC that the subject of hydraulic fracturing is adequately regulated by the states and needs no further study. In my opinion too frequent nationwide or federal study and review of critical operations like hydraulic fracturing, underground injection, and RCRA class II waste exemptions create an environment of uncertainty and litigation that inhibits real progress in sustainable resources development.
Complaints of ground water contamination attributed to hydraulic fracturing or any other oil and gas operation should continue to be investigated by the appropriate state agency or agencies to determine whether or not ground water has been affected and whether a cause and effect relationship can be established between any
impacts to ground water and petroleum exploration and production activities.
Source: http://www.gpo.gov/fdsys/pkg/CHRG-111hhrg50120/pdf/CHRG-111hhrg50120.pdf

Oversight Hearing before the Subcommittee on Energy and Mineral Resources of the On Natural Resources US House of Representatives, One Hundred Eleventh Congress, First Session (Serial No. 111-22)
June 4, 2009
Representative Martin T. Heinrich of New Mexico
You mentioned, Mr. Kell, the letter from New Mexico regarding the fact that we really don't have a big issue with this in terms of contaminating usable water underground, but we still are grappling with contamination, basically, of surface water—some of it histrical and some more recent based on this whole idea of good housekeeping and the best way to do that.
My concern is what do we do with these fluids when they are back on the surface? What level of uniformity and consistency is there of making sure that we are doing a good job disposing of these fluids and other waste products that are inherent to the oil and gas business once they are on the surface, and how do we continue to improve that process? In addition, I would mention that while we had zero cases of usable groundwater contamination, we have a number of cases of surface water contamination from products at the surface.
Source: http://www.gpo.gov/fdsys/pkg/CHRG-111hhrg50120/pdf/CHRG-111hhrg50120.pdf

Senate Committee on Environment and Public Works hearing
December 8, 2009
Sen. James Inhofe of Oklahoma
The following information was released by the U.S. Senate Committee on Environment and Public Works.
During today's Senate Committee on Environment and Public Works hearing on "Federal Drinking Water Programs," Senator Inhofe asked officials from the Environmental Protection Agency (EPA) and the United States Geological Survey (USGS) if they were aware of any documented cases of hydraulic fracturing contamination. None of the three witnesses could provide a single example. Testifying before the EPW Committee today was Peter Silva, Assistant Administrator for Water, Environmental Protection Agency, Cynthia Giles, Assistant Administrator for Enforcement and Compliance Assurance, Environmental Protection Agency, and Matthew Larsen, Associate Director for Water, U.S. Geological Survey.
Full Transcript of Exchange:
Senator Inhofe: I'm anxious to get to this second panel, Madame Chairman. I can't remain silent after Senator Lautenberg's statement about hydraulic fracturing. I have something to say about that, but first, I want to ask all three of you and response: Do any one of you know of one case of ground water contamination that has resulted from hydraulic fracturing? Start with you, Mr. Silva.
Peter Silva: Not that I'm aware of, no.
Senator Inhofe: Ms. Giles?
Cynthia Giles: I understand there's some anecdotal evidence, but I don't know that it's been firmly established.
Senator Inhofe: So the answer is no, you don't know of it.
Cynthia Giles nods.
Senator Inhofe: Alright, Mr. Larsen?
Matthew Larsen: I'll have to respond in writing, I don't, I'm not aware of all of our studies on that topic.
Senator Inhofe: Well, but you've already answered. You're not aware. That's the question I asked you. Here's the problem we have. Senator Lautenberg referred to this as something that's new. This isn't new. It's been around over fifty years. And, we do approximately thirty-five thousand wells a year - nearly a million wells, without one documented case of groundwater contamination. I'm concerned about this, because I know for a fact that if you took away the ability, as all other countries do, of

hydraulic fracturing, we're going to become much more dependent upon other countries for our ability to produce oil. Now, I want to repeat that one more time that there has never been a documented case in almost a million uses of that technology. The EPA did an extensive study of this back, prior to, it lasted a long period of time, they concluded in 2004 that it does not warrant any further study."
Source: http://www.ocapl.org/en/articles/printview.asp?15

Senator Inhofe
March 7, 2002
"How does hydraulic fracturing fit into this equation? This system has been used—I remember using it myself—since the 1940s. In the 1940s, we had a system of injection in order to get maximum production in both oil and gas wells. Not one time in that period of time—after over a million wells have used this process—has there been any kind of damage to the environment. In the last 15 years, there have been over 100,000 wells using this, with no damage to the environment.
As the Senator from New Mexico points out, this is not a partisan thing. The Clinton administration supported this, the Bush administration supports this, and Carol Browner supported this when I served as chairman of one of the subcommittees of the Environment and Public Works Committee. This is necessary to have, and it does no harm to the environment."
Source: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=2002_record&docid=DOCID:cr07mr02-119.pdf

Carol Browner, then Administrator of the U.S. Environmental Protection Agency
May 5, 1995
"There is no evidence that the hydraulic fracturing at issue has resulted in any contamination or endangerment of underground sources of drinking water (USDW). Repeated testing, conducted between May of 1989 and March of 1993, of the drinking water well which was the subject of this petition failed to show any chemicals that would indicate the presence of fracturing fluids. The well was also sampled for drinking water quality and no constituents exceeding drinking water standards were detected. Moreover, given the horizontal and vertical distance between the drinking water well and the closest methane gas production wells, the possibility of contamination or endangerment of USDWs in the area is extremely remote."
Source: http://www.gpo.gov/fdsys/pkg/CREC-2002-03-07/pdf/CREC-2002-03-07-pt1-PgS1621-8.pdf

Senator Jeff Bingaman of New Mexico
March 7, 2002
"And although there have been over a million hydraulic fracturing jobs conducted in the last 5 years, there have been zero confirmed instances of hydraulic fracturing contaminating drinking water. There is not one time that contamination has been established."
Source: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=2002_record&docid=DOCID:cr07mr02-119.pdf

Senator Jeff Sessions of Alabama
March 7, 2002:
"Most States in which hydraulic fracturing is used -- including my State of Alabama -- have implemented regulations to ensure that hydraulic fracturing continues to be used in a safe manner. The technique has been used safely by coalbed methane oil and gas producers for over 15 years, and there has never been a single event of contamination to underground drinking sources."

Source: http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=2002_record&docid=DOCID:cr07mr02-119.pdf

Western Energy Alliance: "There are no documented cases of contamination to drinking water from fracing."
Source: http://westernenergyalliance.org/wp-content/uploads/docs/legislative/IPAMS%20Position%20Paper%20-%20Hydraulic%20Fracturing.pdf
Context: Position paper

Elizabeth Ames Jones, Texas Railroad Commission
July 9, 2010
"Based on the facts, one can be confident that the geology in Texas, combined with safeguards that we require in the drilling of a well, simply do not support the notion that water used in hydraulic fracturing will migrate to a water table. With many thousands of fracs taking place in Texas, Commission records do not indicate a single documented water contamination case associated with hydraulic fracturing in our state."
Source: http://www.texasinsider.org/?p=29927

New York State Department of Environmental Conservation: "As a result of New York's rigorous regulatory process, the types of problems reported to have occurred in states without such strong environmental laws and rigorous regulations haven't happened here. No known instances of groundwater contamination have occurred from previous horizontal drilling or hydraulic fracturing projects in New York State."
Source: http://www.dec.ny.gov/energy/46288.html

Energy Tomorrow, an American Petroleum Institute blog by Jane Van Ryan
Nov. 12, 2010
"U.S. government studies have found no evidence of drinking water contamination from hydraulic fracturing. In 2004, the Environmental Protection Agency (EPA) conducted a study to assess the contamination potential of underground drinking water sources (UDWS) from the injection of hydraulic fracturing fluid into coalbed methane (CBM) wells. EPA found 'the injection of hydraulic fracturing fluids into CBM wells poses little or no threat to USDWs and does not justify additional study at this time.' EPA also reviewed incidents of drinking water well contamination believed to be associated with hydraulic fracturing operations. It found 'no confirmed cases linked to fracturing fluid injection of CBM wells or subsequent underground movement of fracturing fluid.'
In 1998, the Ground Water Protection Council (GWPC) and a team of state agency representatives conducted a survey of state oil and natural gas agencies to establish an accurate assessment of the number of active CBM wells associated with hydraulic fracturing. Based on the survey of 25 oil and natural gas producing states, the GWPC concluded, 'there was no evidence to support claims that public health is at risk as a result of the hydraulic fracturing of coalbeds used for the production of methane gas.'
EPA is developing a study plan now for a congressionally-mandated review of the relationship between hydraulic fracturing and drinking water. The study is expected to be finished in 2012.
A recent documentary about hydraulic fracturing implies that fracturing has contaminated water wells in Pennsylvania. However, John Hanger, secretary of the Department of Environmental Protection (DEP) recently told Reuters, 'It's our experience in Pennsylvania that we have not had one case in

which the fluids used to break off the gas from 5,000 to 8,000 feet underground have returned to contaminate ground water.'"
Source: http://blog.energytomorrow.org/2010/11/addressing-hydraulic-fracturing-issues-one-by-one.html

Kathryn Klaber, President of the Marcellus Shale Coalition
July 23, 2010
"My name is Kathryn Klaber, and I have the tremendous privilege of serving as the Marcellus Shale Coalition's first president. And on behalf of the MSC – the organizational body that represents the vast majority of shale gas producers and midstream companies operating in the Commonwealth – I appreciate the opportunity to discuss the significant role hydraulic fracturing continues to play in the responsible development of clean-burning, job-creating natural gas.
As the MSC said at the outset of this study in March, our industry is confident that an objective, science-driven, and peer-reviewed evaluation of fracturing will reach the same conclusions produced by a host of other studies, including most notably one issued by your agency in 2004.
In that report — the product of an intensive, four-year course of study first initiated under the Clinton administration — EPA found 'no evidence' suggesting the fracturing of shallow coalbed methane reserves posed a threat to underground drinking water supplies. Certainly you're aware that coalbed methane strata reside thousands of feet closer to the water table than shale formations, and that the technology used today to access clean-burning natural gas from these formations is much more advanced and sophisticated than what was available in the past.
Here in Pennsylvania, fracturing has been in use for more than 50 years, and has been tightly regulated by the state almost before we had a name for it. Today, as you know, fracturing is considered a safe and essential part of the responsible development of natural gas, which studies have shown has the potential to create nearly 212,000 new jobs throughout Pennsylvania over the next decade.
Because of tight regulations and laws in place, coupled with the commitment from industry to protect the environment, there's never been a single case of groundwater contamination associated with fracturing, as noted by PA DEP, top EPA officials, other state regulators, and the Groundwater Protection Council.
As EPA's study moves forward, it's critical to consider what the top officials responsible for regulating fracturing in the Commonwealth have said. Scott Perry, director of DEP's bureau of oil and gas management – with whom my members work closely with – said this in May:
'We've never seen an impact to fresh groundwater directly from fracking.'
'No one's ever documented drinking water wells that have actually been shown to be impacted by fracking.'"
Source: http://marcelluscoalition.org/2010/07/msc-to-epa-hydraulic-fracturing-is-%E2%80%9Ca-safe-essential-part-of-the-responsible-development-of-natural-gas%E2%80%9D/

Representative John Sullivan of Oklahoman and Representative Mike Ross of Arkansas
April 27, 2010 letter to colleagues
"Hydraulic fracturing plays a major role in the development of virtually all unconventional oil and natural gas resources – as you mentioned in your memo to members of the Energy and Environment Subcommittee on February 18th of this year – and thus should not be limited in the absence of any evidence that fracturing has damaged the environment. In fact, according to the Interstate Oil and Gas Compact Commission, (IOGCC) approximately 35,000 wells are hydraulically fractured annually in the United States and close to one million wells have been hydraulically fractured in the United States since the technique's inception more than 60 years ago, with no known harm to groundwater.

It is our view that U.S. Environmental Protection Agency (EPA) regulation of hydraulic fracturing under the SDWA would add burdensome and unnecessary regulatory requirements to the drilling and completion of oil and gas wells which could result in increasing costs of producing domestic natural gas resources without any additional benefit to public health, safety or the environment. This is especially concerning in light of little to no evidence that the use of hydraulic fracturing has contaminated drinking water supplies."
Source: http://sullivan.house.gov/News/DocumentSingle.aspx?DocumentID=182833

Lisa Jackson, Administrator, U.S. Environmental Protection Agency
May 24, 2011
Ms. Jackson was asked during a Committee on Oversight and Government Reform hearing held by the U.S. House of Representatives: "Is there any evidence, however, that hydraulic fracturing can affect aquifers and water supplies?"

Lisa Jackson: "There is evidence that it can certainly affect them. I am not aware of any proven case where the fracking process itself has affected water although there are investigations ongoing."

Source: http://www.youtube.com/watch?v=2Z-lE5p1fZk